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Docket No. 20200007-EI
Comprehensive Exhibit List for Entry into Hearing Record
November 3, 2020

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
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2	Renae B. Deaton	RBD-1	Environmental Cost Recovery Final True-up January 2019 - December 2019 Commission Forms 42-1A through 42-9A	1	
3	Renae B. Deaton	RBD-2	Environmental Cost Recovery Actual/Estimated True-up January 2020 - December 2020 Commission Forms 42-1E through 42-9E	2	
4	Renae B. Deaton	RBD-3	Appendix I - Environmental Cost Recovery Projections - January 2021 - December 2021 Commission Forms 42-1P through 42-8P Appendix II - Calculation of Stratified Separation Factors	3-10, 14	
5	Michael W. Sole	MWS-1 (5)	FPL Supplemental CAIR/MATS/CAVR Filing	1, 2	
6	Michael W. Sole	MWS-2 (6)	June 12, 2019 NOAA Letter to FPL	13	
7	Michael W. Sole	MWS-3	March 25, 2020 USFWS Letter to FPL	13	
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9	Michael W. Sole	MWS-5	June 2016 FDEP Consent Order	15	

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11	Michael W. Sole	MWS-7	July 2020 Plan Submitted to FDEP	15	
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15	Richard L. Hume	RLH-1	Environmental Cost Recovery Final True-up January 2019 - December 2019 Commission Forms 42-1A through 42-9A	1-10	
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21	Christopher Menendez	CAM-1	Forms 42-1A - 42-9A January 2019 – December 2019	1-12	
22	Christopher Menendez	CAM-2	Capital Program Detail January 2019 – December 2019	1-12	

23	Christopher Menendez	CAM-3	Forms 42-1E – 42-9E January 2020 – December 2020	1-12	
24	Christopher Menendez	CAM-4	Capital Program Detail January 2020 – December 2020	1-12	
25	Christopher Menendez	CAM-5	Forms 42-1P – 42-8P January 2021 – December 2021	1-12	
26	Christopher Menendez	CAM-6	Capital Program Detail January 2021 – December 2021	1-12	
27	Timothy Hill	CAM-5 (27)	Form 42-5P, page 23 of 23	1-3	
28	Jeffrey Swartz	JS-1	Crystal River Clean Air Projects Organizational Chart	1-3	
29	Jeffrey Swartz	CAM-5 (29)	Form 42-5P, pages 7, 21 and 22 of 23	1-3	
30	Kim Spence McDaniel	KSM-1	Review of Integrated Clean Air Compliance Plan	1-3, 11	
31	Kim Spence McDaniel	CAM-5 (31)	Form 42-5P, pages 1-4 and 6-20 of 23	1-3, 11	
TAMPA ELECTRIC COMPANY – DIRECT					
32	M. Ashley Sizemore	MAS-1	Final Environmental Cost Recovery Commission Forms 42-1A through 42-9A for the period January 2019 through December 2019	1-9	
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STAFF HEARING EXHIBITS					
35	Sole (1-2)		FPL's response to Staff's First Set of Interrogatories Nos. 1-2 *[Bates Nos. 00001-00003]*	1, 2, 3	
36	Sole (3-12, 14) Deaton (13)		FPL's response to Staff's Second Set of Interrogatories Nos. 3-14 *[Bates Nos. 00004-00016]*	1, 4, 5, 6, 7, 8, 13, 14	
37	Deaton (15) Sole (16-18)		FPL's response to Staff's Third Set of Interrogatories Nos. 15-18 *[Bates Nos. 00017-00022]*	2, 4, 5, 6, 7, 8, 15	
38	Deaton (19) Sole (19-21)		FPL's response to Staff's Fourth Set of Interrogatories Nos. 19-21 *[Bates Nos. 00023-00026]*	3, 4, 5, 6, 7, 8, 13, 14, 15	
39	Sole (1-7) Hume (8-9)		Gulf's response to Staff's First Set of Interrogatories Nos. 1-9 *[Bates Nos. 00027-00036]*	1, 4, 5, 6, 7, 8	
40	Sole (10)		Gulf's response to Staff's Second Set of Interrogatories No. 10 *[Bates Nos. 00037-00041]*	2, 4, 5, 6, 7, 8	
41	Borsch (1)		DEF's response to Staff's First Set of Interrogatories No. 1 *[Bates Nos. 00042-00047]*	1, 2, 3	
42	McDaniel (2a, 3) Swartz (2b, 2c) Borsch (4)		DEF's response to Staff's Second Set of Interrogatories Nos. 2-4 *[Bates Nos. 00048-00055]*	1, 4, 5, 6, 7, 8	
43	McDaniel (5) Borsch (6)		DEF's response to Staff's Third Set of Interrogatories Nos. 5-6 *[Bates Nos. 00056-00060]*	3, 4, 5, 6, 7, 8, 11, 12	

44	McDaniel (7-8)		DEF's response to Staff's Fourth Set of Interrogatories Nos. 7-8 *[Bates Nos. 00061-00062]*	2, 4, 5, 6, 7, 8	
45	McDaniel (9-12) Hill (13) Swartz (14-18)		DEF's response to Staff's Fifth Set of Interrogatories Nos. 9-18 *[Bates Nos. 00063-00067]*	3, 4, 5, 6, 7, 8	
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47	Sizemore (3-4)		TECO's response to Staff's Second Set of Interrogatories Nos. 3-4 *[Bates Nos. 00075-00079]*	1, 4, 5, 6, 7, 8	
48	Sizemore (5-6)		TECO's response to Staff's Third Set of Interrogatories Nos. 5-6 *[Bates Nos. 00080-00084]*	2, 4, 5, 6, 7, 8	
49	Sizemore (7)		TECO's response to Staff's Fourth Set of Interrogatories No. 7 *[Bates Nos. 00085-00086]*	3, 4, 5, 6, 7, 8	

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

FORM: 42-1A

JANUARY 2019 THROUGH DECEMBER 2019

	2019
1. Over/(Under) Recovery for the Current Period (Form 42-2A, Line 5)	$20,291,401
2. Interest Provision (Form 42-2A, Line 6)	$914,353
3. Total	$21,205,754
4. Actual/Estimated Over/(Under) Recovery for the Same Period [(a)]	$6,177,306
5. Interest Provision	$940,505
6. Total	$7,117,811
7. Net True-Up for the period Over/(Under) Recovery	$14,087,943

[(a)] Approved in Order No. PSC-2019-0500-FOF-EI issued on November 22, 2019□

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 2
PARTY: RBD-1
DESCRIPTION: Environmental Cost Recovery Final True-up January 2019 - December 2019 Commission Forms 42-1A throu...

Docket No. 20200007-EI
2019 ECR Final True Up Calculation
Exhibit RBD-1, Page 1 of 71

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

FORM: 42-2A

JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Total
1. ECRC Revenues (net of Revenue Taxes)	$12,045,955	$10,950,339	$11,895,094	$12,558,139	$13,758,679	$15,724,266	$16,511,067	$16,291,745	$16,683,316	$15,574,672	$13,865,936	$11,580,699	$167,439,907
2. True-up Provision [a]	$2,162,138	$2,162,138	$2,162,138	$2,162,138	$2,162,138	$2,162,138	$2,162,138	$2,162,138	$2,162,138	$2,162,138	$2,162,138	$2,162,138	$25,945,661
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$14,208,094	$13,112,477	$14,057,232	$14,720,278	$15,920,817	$17,886,404	$18,673,206	$18,453,884	$18,845,454	$17,736,810	$16,028,074	$13,742,837	$193,385,568
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5A-2, Line 9)	$2,823,987	$2,640,073	$2,748,033	$2,873,274	$2,426,754	$2,490,857	$2,803,181	$2,448,209	$1,800,749	$1,713,751	$2,329,994	$2,726,015	$29,824,876
b. Capital Investment Projects (Form 42-7A-2, Line 8)	$11,607,563	$11,754,779	$11,754,854	$11,750,779	$11,718,395	$11,731,570	$12,151,954	$12,144,859	$12,136,818	$12,131,793	$12,128,530	$12,257,398	$143,269,291
c. Total Jurisdictional ECRC Costs	$14,431,550	$14,394,852	$14,502,886	$14,624,053	$14,145,149	$14,222,426	$14,955,136	$14,593,068	$13,937,567	$13,845,543	$14,458,523	$14,983,413	$173,094,167
5. Over/(Under) Recovery (Line 3 - Line 4c)	($223,456)	($1,282,375)	($445,654)	$96,225	$1,775,668	$3,663,978	$3,718,070	$3,860,815	$4,907,887	$3,891,267	$1,569,551	($1,240,576)	$20,291,401
6. Interest Provision (Form 42-3A, Line 10)	$94,671	$88,800	$83,918	$79,652	$75,889	$75,401	$73,713	$72,151	$73,734	$70,077	$65,171	$61,176	$914,353
7. Prior Periods True-Up to be (Collected)/Refunded	$25,945,661	$23,654,738	$20,299,024	$17,775,150	$15,788,888	$15,478,308	$17,055,548	$18,685,192	$20,456,021	$23,275,504	$25,074,709	$24,547,293	$25,945,661
a. Deferred True-Up (Form 42-1A, Line 7) [b]	$22,191,591	$22,191,591	$22,191,591	$22,191,591	$22,191,591	$22,191,591	$22,191,591	$22,191,591	$22,191,591	$22,191,591	$22,191,591	$22,191,591	
8. True-Up Collected /(Refunded) (See Line 2)	($2,162,138)	($2,162,138)	($2,162,138)	($2,162,138)	($2,162,138)	($2,162,138)	($2,162,138)	($2,162,138)	($2,162,138)	($2,162,138)	($2,162,138)	($2,162,138)	($25,945,661)
9. End of Period True-Up (Lines 5+6+7+7a+8)	$45,846,329	$42,490,615	$39,966,740	$37,980,479	$37,669,898	$39,247,138	$40,876,783	$42,647,611	$45,467,095	$47,266,300	$46,738,883	$43,397,345	$21,205,754
10. Adjustments to Period Total True-Up Including Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11. End of Period Total Net True-Up (Lines 9+10)	$45,846,329	$42,490,615	$39,966,740	$37,980,479	$37,669,898	$39,247,138	$40,876,783	$42,647,611	$45,467,095	$47,266,300	$46,738,883	$43,397,345	$21,205,754

[a] As approved in Order No. PSC-2018-0594-FOF-EI issued December 20, 2018.
[b] From FPL's 2018 Final True-up filed on April 1,2019.

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

FORM: 42-3A

JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	
	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1. Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$48,137,252	$45,846,329	$42,490,615	$39,966,740	$37,980,479	$37,669,898	$39,247,138	$40,876,783	$42,647,611	$45,467,095	$47,266,300	$46,738,883	N/A
2. Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	$45,751,657	$42,401,815	$39,882,823	$37,900,827	$37,594,009	$39,171,738	$40,803,070	$42,575,460	$45,393,360	$47,196,223	$46,673,712	$43,336,169	N/A
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$93,888,909	$88,248,144	$82,373,438	$77,867,567	$75,574,488	$76,841,636	$80,050,209	$83,452,243	$88,040,972	$92,663,318	$93,940,012	$90,075,052	N/A
4. Average True-Up Amount (Line 3 x 1/2)	$46,944,455	$44,124,072	$41,186,719	$38,933,784	$37,787,244	$38,420,818	$40,025,104	$41,726,122	$44,020,486	$46,331,659	$46,970,006	$45,037,526	N/A
5. Interest Rate (First Day of Reporting Month)	2.42000%	2.42000%	2.41000%	2.48000%	2.43000%	2.39000%	2.32000%	2.10000%	2.05000%	1.97000%	1.66000%	1.67000%	N/A
6. Interest Rate (First Day of Subsequent Month)	2.42000%	2.41000%	2.48000%	2.43000%	2.39000%	2.32000%	2.10000%	2.05000%	1.97000%	1.66000%	1.67000%	1.59000%	N/A
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	4.84000%	4.83000%	4.89000%	4.91000%	4.82000%	4.71000%	4.42000%	4.15000%	4.02000%	3.63000%	3.33000%	3.26000%	N/A
8. Average Interest Rate (Line 7 x 1/2)	2.42000%	2.41500%	2.44500%	2.45500%	2.41000%	2.35500%	2.21000%	2.07500%	2.01000%	1.81500%	1.66500%	1.63000%	N/A
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.20167%	0.20125%	0.20375%	0.20458%	0.20083%	0.19625%	0.18417%	0.17292%	0.16750%	0.15125%	0.13875%	0.13583%	N/A
10. Interest Provision for the Month (Line 4 x Line 9)	$94,671	$88,800	$83,918	$79,652	$75,889	$75,401	$73,713	$72,151	$73,734	$70,077	$65,171	$61,176	$914,353

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

FORM: 42-4A-1

JANUARY 2019 THROUGH DECEMBER 2019
VARIANCE REPORT OF O&M ACTIVITES

(1)	(2)	(3)	(4)	(5)
O&M Projects	ECRC - 2019 Final True-Up [a]	ECRC - 2019 Actual/Estimated [b]	Dif. ECRC - 2019 Actual/Estimated [c]	% Dif. ECRC - 2019 Actual/Estimated [d]
1 - Air Operating Permit Fees	$274,854	$225,740	$49,115	21.8%
3a - Continuous Emission Monitoring Systems	$619,386	$669,899	($50,513)	(7.5%)
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	$724,412	$640,599	$83,814	13.1%
8a - Oil Spill Clean-up/Response Equipment	($257,366)	$182,377	($439,743)	(241.1%)
NA-Amortization of Gains on Sales of Emissions Allowances	($425)	($425)	$0	0.0%
14 - NPDES Permit Fees	$76,700	$69,450	$7,250	10.4%
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$4,255,702	$3,019,288	$1,236,415	41.0%
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$1,061,315	$833,320	$227,995	27.4%
19c - Substation Pollutant Discharge Prevention & Removal - Base [e]	$168	$0	$168	
21 - St. Lucie Turtle Nets	$422,103	$355,961	$66,142	18.6%
22 - Pipeline Integrity Management	$56,475	$79,525	($23,050)	(29.0%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$846,683	$763,837	$82,846	10.8%
24 - Manatee Reburn	$141,489	$219,249	($77,760)	(35.5%)
27 - Lowest Quality Water Source	$134,864	$143,857	($8,993)	(6.3%)
28 - CWA 316(b) Phase II Rule	$1,013,956	$1,133,263	($119,307)	(10.5%)
29 - SCR Consumables	$493,644	$551,135	($57,490)	(10.4%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$3,649,745	$3,920,827	($271,081)	(6.9%)
33 - MATS Project	$2,107,246	$2,104,512	$2,734	0.1%
35 - Martin Plant Drinking Water System Compliance	$35,881	$33,137	$2,744	8.3%
37 - DeSoto Next Generation Solar Energy Center	$758,349	$620,706	$137,643	22.2%
38 - Space Coast Next Generation Solar Energy Center	$263,904	$268,389	($4,485)	(1.7%)
39 - Martin Next Generation Solar Energy Center	$3,887,230	$3,366,532	$520,698	15.5%
41 - Manatee Temporary Heating System	$164,863	$176,855	($11,992)	(6.8%)
42 - Turkey Point Cooling Canal Monitoring Plan	$9,248,061	$20,010,655	($10,762,593)	(53.8%)
45 - 800 MW Unit ESP	$113,093	$265,008	($151,915)	(57.3%)
47 - NPDES Permit Renewal Requirements	$593,698	$611,151	($17,453)	(2.9%)
48 - Industrial Boiler MACT	$28,433	$32,000	($3,567)	(11.1%)
50 - Steam Electric Effluent Guidelines Revised Rules	$228,793	$188,100	$40,694	21.6%
51 - Gopher Tortoise Relocations	$21,624	$25,649	($4,025)	(15.7%)
54 - Coal Combustion Residuals	$0	$261,852	($261,852)	(100.0%)
55 - Solar Site Avian Monitoring and Reporting Project	$128,742	$113,162	$15,580	13.8%
Total	31,093,625	40,885,609	(9,791,983)	(23.9%)

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

[b] The approved amount in accordance with FPSC Order No. PSC-2019-0500-FOF-EI

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

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

[e] The amount displayed in 19c O&M cost was booked in error to the project internal order. The charge was reversed March 2020.

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

FORM: 42-4A

JANUARY 2019 THROUGH DECEMBER 2019
VARIANCE REPORT OF O&M ACTIVITES

(1)	(2)	(3)	(4)	(5)
	ECRC - 2019 Final True-Up (a)	ECRC - 2019 Actual/Estimated (b)	Dif. ECRC - 2019 Actual/Estimated (c)	% Dif. ECRC - 2019 Actual/Estimated (d)
2. Total of O&M Activities	$31,093,625	$40,885,609	($9,791,983)	(23.95%)
3. Recoverable Costs Allocated to Energy	$16,683,333	$28,438,993	($11,755,660)	(41.34%)
4a. Recoverable Costs Allocated to CP Demand	$10,154,590	$9,427,328	$727,262	7.71%
4b. Recoverable Costs Allocated to GCP Demand	$4,255,702	$3,019,288	$1,236,415	40.95%
5. Jurisdictional Energy Recoverable Costs	$15,984,184	$27,258,158	($11,273,974)	(41.36%)
6a. Jurisdictional CP Demand Recoverable Costs	$9,584,990	$8,916,093	$668,896	7.50%
6b. Jurisdictional GCP Demand Recoverable Costs	$4,255,702	$3,019,288	$1,236,415	40.95%
7. Total Jurisdictional Recoverable Costs for O&M Activities	$29,824,876	$39,193,539	($9,368,663)	(23.90%)

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

(b) The approved amount in accordance with FPSC Order No. PSC-2019-0500-FOF-EI

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

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

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

FORM: 42-5A

JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
O&M Projects	Strata	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
1 - Air Operating Permit Fees	Base	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$133,620
1 - Air Operating Permit Fees	Intermediate	($19,175)	$5,823	$2,092	$5,823	$5,823	$5,823	$5,823	$5,823	$5,823	$5,823	$18,694	$18,694	$66,891
1 - Air Operating Permit Fees	Peaking	$1,948	$1,948	$13,740	$1,948	$1,948	$1,948	$1,948	$1,948	$1,948	$1,948	$21,536	$21,536	$74,344
3a - Continuous Emission Monitoring Systems	Intermediate	$216,413	$106,546	$44,095	$22,507	$13,533	$4,326	$41,130	$1,247	$37,917	$19,228	$10,872	$40,626	$558,439
3a - Continuous Emission Monitoring Systems	Peaking	$37,451	$14,775	$878	$398	($519)	($1,794)	$816	$0	$209	$441	$8,165	$128	$60,947
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$0	$0	$0	$0	$3,325	$0	$0	$0	$0	$0	$0	$0	$3,325
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$100,540	$95	$2,570	$21,203	$2,668	($17,222)	$0	$158,846	$93,214	$12,256	$0	$56,938	$431,107
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$275	$90,952	$97,388	($21,203)	$7,256	$2	$46	$32,200	$8,412	$2,197	$0	$72,454	$289,980
8a - Oil Spill Clean-up/Response Equipment	Base	$2	$0	$0	$15	$3	$41	$3	$24	($89)	$0	$0	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Intermediate	$838	$1,162	$893	$692	$2,059	$1,575	$8,117	($7,017)	$7,104	($54,506)	$2,175	$8,598	($28,310)
8a - Oil Spill Clean-up/Response Equipment	Peaking	$6,790	$9,403	$7,222	$5,680	$16,674	$12,960	$65,692	($56,649)	$57,013	($441,003)	$17,599	$69,563	($229,056)
14 - NPDES Permit Fees	Base	$11,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,500
14 - NPDES Permit Fees	Intermediate	$28,260	$0	$0	$0	$250	$0	($250)	$0	$0	$0	$0	$3,300	$31,560
14 - NPDES Permit Fees	Peaking	$29,440	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,200	$33,640
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$581,140	$415,648	$317,674	$620,244	$260,581	$232,886	$422,471	$382,208	$393,701	$190,939	$120,879	$317,331	$4,255,702
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$61,594	$208,672	$100,835	$83,695	$17,006	$26,017	$273,118	$63,732	$97,237	$48,053	$39,749	$41,608	$1,061,315
19c - Substation Pollutant Discharge Prevention & Removal - Base [a]	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$168	$168
21 - St. Lucie Turtle Nets	Base	($6,600)	$0	$127,989	($26,778)	$46,451	$53,880	$14,859	$29,715	$121,582	$20,265	$13,965	$26,775	$422,103
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($4)	($4)	($4)	($4)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($70)
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	($12)	($12)	($12)	($12)	($12)	($25)	($25)	($25)	($25)	($25)	($25)	($25)	($235)
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	($6)	($6)	($6)	($6)	($6)	($13)	($13)	($13)	($13)	($13)	($13)	($13)	($119)
22 - Pipeline Integrity Management	Intermediate	$0	$0	$1,717	$0	$0	$0	$0	$0	$0	$0	$21,717	$0	$23,433
22 - Pipeline Integrity Management	Peaking	$0	$0	$2,420	$0	$0	$0	$0	$0	$0	$0	$30,621	$0	$33,042
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$26,612	$54,023	$78,651	$44,795	$52,721	$38,008	$66,849	$60,996	$51,585	$54,422	$34,439	$42,637	$605,737
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$5,815	$0	$5,475	$0	$2,903	$12,482	$3,026	$0	$990	$1,027	$43	($95)	$31,665
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$10,703	$0	$3,263	$0	$2,364	$10,309	$748	$0	$625	$461	$0	$783	$29,255
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$11,092	$11,986	$49,578	$9,586	$12,897	$8,360	$14,872	$11,692	$14,994	$12,593	$9,584	$12,792	$180,025
24 - Manatee Reburn	Peaking	$56,795	$8,420	$4,248	$0	$59,308	$12,556	$37	$0	$0	$0	$0	$125	$141,489
27 - Lowest Quality Water Source	Intermediate	$11,301	$11,849	$11,285	$10,140	$10,282	$11,582	$11,442	$11,483	$11,154	$11,467	$11,451	$11,428	$134,864
28 - CWA 316(b) Phase II Rule	Base	$13,937	$13,871	$7,435	$6,992	$11,129	$12,720	$9,848	$10,579	$6,522	$5,544	$9,188	$9,271	$117,036
28 - CWA 316(b) Phase II Rule	Intermediate	$80,552	$58,998	$48,742	$65,219	$58,041	$34,812	$58,657	$61,669	$50,919	$113,546	$57,318	$101,375	$789,848
28 - CWA 316(b) Phase II Rule	Peaking	$27,041	$8,202	$9,574	$360	$25,048	($22,515)	$12,744	($15,017)	$19,567	$26,690	($455)	$15,832	$107,072
29 - SCR Consumables	Intermediate	$25,460	$47,454	$11,209	$25,841	$42,509	$41,806	$30,124	$19,345	$36,005	$22,950	$76,566	$114,374	$493,644
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$205,845	$443,059	$139,381	$337,365	$365,480	$353,706	$306,121	$343,257	$196,138	$332,871	$257,387	$234,932	$3,515,542
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$10,028	$745	$9,839	$9,965	$10,218	$12,389	$23,887	$12,798	$13,935	$10,234	$10,327	$9,839	$134,204
33 - MATS Project	Base	$254,640	$179,781	$92,006	$155,416	$129,274	$138,314	$219,277	$191,398	$121,925	$183,677	$270,281	$171,257	$2,107,246
35 - Martin Plant Drinking Water System Compliance	Peaking	$5,053	$2,500	$107	$5,053	$2,553	$2,553	$85	$7,660	$2,710	$2,500	$0	$5,107	$35,881
37 - DeSoto Next Generation Solar Energy Center	Solar	$71,028	$62,362	$73,367	$96,609	$23,760	$98,803	$68,216	$77,732	$78,807	$14,908	$34,010	$58,745	$758,349
38 - Space Coast Next Generation Solar Energy Center	Solar	$30,399	$7,304	$7,781	$8,823	$31,081	$19,893	$54,692	$24,704	$22,061	$27,085	$14,579	$15,502	$263,904
39 - Martin Next Generation Solar Energy Center	Intermediate	$240,387	$199,070	$188,746	$363,705	$443,520	$333,687	$322,576	$348,346	$319,316	$469,359	$314,199	$344,319	$3,887,230
41 - Manatee Temporary Heating System	Intermediate	$3,797	$9,171	$15,647	$6,582	$5,758	$43,462	$6,261	$4,646	$0	$23,569	$11,421	$34,550	$164,863
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$643,830	$475,881	$1,170,088	$1,060,343	$799,306	$1,001,205	$834,335	$678,151	$106,591	$637,306	$982,095	$855,297	$9,244,428
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,001	($368)	$3,633
45 - 800 MW Unit ESP	Peaking	$4,299	$22,144	$57,879	$4,880	$3,027	$3,434	$8,665	$7,280	$0	$0	$1,485	$0	$113,093
47 - NPDES Permit Renewal Requirements	Base	$0	$240,942	$117,270	$28,960	$23,000	$53,625	$12,587	$48,827	($31,725)	$0	$15,456	$61,226	$570,169
47 - NPDES Permit Renewal Requirements	Intermediate	$0	$0	$7,450	$2,513	$0	$0	$0	$953	($477)	$9,363	$0	$2,513	$22,316
47 - NPDES Permit Renewal Requirements	Peaking	$0	$0	$0	$0	$0	$0	$0	$1,213	($607)	$607	$0	$0	$1,213
48 - Industrial Boiler MACT	Base	$0	$0	$0	$0	$0	$196	$2,190	$1,341	$823	$0	$0	$0	$4,549
48 - Industrial Boiler MACT	Peaking	$0	$0	$0	$0	$0	$1,029	$11,495	$7,038	$4,322	$0	$0	$0	$23,884
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$136,847	$22,621	$21,991	$2,318	$4,223	$31,843	($507)	$1,407	$3,055	$2,037	$1,742	$1,118	$228,694
50 - Steam Electric Effluent Guidelines Revised Rules	Peaking	$0	$100	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$100
51 - Gopher Tortoise Relocations	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51 - Gopher Tortoise Relocations	Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,624	$21,624
55 - Solar Site Avian Monitoring and Reporting Project	Solar	($710)	$9,902	$4,259	$11,979	$22,987	$10,369	$7,687	$8,854	$12,314	$10,907	$3,167	$27,027	$128,742
	Total	$2,936,281	$2,756,519	$2,865,896	$2,982,781	$2,529,557	$2,596,161	$2,930,778	$2,549,523	$1,876,710	$1,789,852	$2,435,350	$2,844,220	$31,093,625

[a] The amount displayed in 19c O&M cost was booked in error to the project internal order. The charge was reversed March 2020.

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

FORM: 42-5A

JANUARY 2019 THROUGH DECEMBER 2019

O&M ACTIVITIES

O&M Project	Strata	Monthly Data	Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand	GCP Demand
1 - Air Operating Permit Fees	Base	$133,620	95.9309%	$128,183	$128,183	$0	$0
1 - Air Operating Permit Fees	Intermediate	$66,891	94.4167%	$63,156	$63,156	$0	$0
1 - Air Operating Permit Fees	Peaking	$74,344	95.5155%	$71,010	$71,010	$0	$0
3a - Continuous Emission Monitoring Systems	Intermediate	$558,439	94.4167%	$527,260	$527,260	$0	$0
3a - Continuous Emission Monitoring Systems	Peaking	$60,947	95.5155%	$58,213	$58,213	$0	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$3,325	95.7589%	$3,184	$0	$3,184	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$431,107	94.2474%	$406,307	$0	$406,307	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$289,980	95.3443%	$276,479	$0	$276,479	$0
8a - Oil Spill Clean-up/Response Equipment	Base	$0	95.9309%	$0	$0	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Intermediate	($28,310)	94.4167%	($26,730)	($26,730)	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Peaking	($229,056)	95.5155%	($218,784)	($218,784)	$0	$0
14 - NPDES Permit Fees	Base	$11,500	95.7589%	$11,012	$0	$11,012	$0
14 - NPDES Permit Fees	Intermediate	$31,560	94.2474%	$29,744	$0	$29,744	$0
14 - NPDES Permit Fees	Peaking	$33,640	95.3443%	$32,074	$0	$32,074	$0
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$4,255,702	100.0000%	$4,255,702	$0	$0	$4,255,702
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$1,061,315	89.2071%	$946,768	$0	$946,768	$0
19c - Substation Pollutant Discharge Prevention & Removal - Base [(a)]	Transmission	$168	89.2071%	$150	$0	$150	$0
21 - St. Lucie Turtle Nets	Base	$422,103	95.7589%	$404,201	$0	$404,201	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($70)	95.9309%	($68)	($68)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	($235)	94.4167%	($222)	($222)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	($119)	95.5155%	($114)	($114)	$0	$0
22 - Pipeline Integrity Management	Intermediate	$23,433	94.2474%	$22,085	$0	$22,085	$0
22 - Pipeline Integrity Management	Peaking	$33,042	95.3443%	$31,503	$0	$31,503	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$31,665	94.2474%	$29,844	$0	$29,844	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$29,255	95.3443%	$27,893	$0	$27,893	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$605,737	100.0000%	$605,737	$0	$605,737	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$180,025	89.2071%	$160,595	$0	$160,595	$0
24 - Manatee Reburn	Peaking	$141,489	95.5155%	$135,144	$135,144	$0	$0
27 - Lowest Quality Water Source	Intermediate	$134,864	94.2474%	$127,106	$0	$127,106	$0
28 - CWA 316(b) Phase II Rule	Base	$117,036	95.7589%	$112,072	$0	$112,072	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$789,848	94.2474%	$744,411	$0	$744,411	$0
28 - CWA 316(b) Phase II Rule	Peaking	$107,072	95.3443%	$102,087	$0	$102,087	$0
29 - SCR Consumables	Intermediate	$493,644	94.4167%	$466,083	$466,083	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,515,542	95.9309%	$3,372,491	$3,372,491	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$134,204	95.5155%	$128,185	$128,185	$0	$0
33 - MATS Project	Base	$2,107,246	95.9309%	$2,021,500	$2,021,500	$0	$0
35 - Martin Plant Drinking Water System Compliance	Peaking	$35,881	95.3443%	$34,210	$0	$34,210	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$758,349	95.7589%	$726,187	$0	$726,187	$0
38 - Space Coast Next Generation Solar Energy Center	Solar	$263,904	95.7589%	$252,712	$0	$252,712	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$3,887,230	94.2474%	$3,663,613	$0	$3,663,613	$0
41 - Manatee Temporary Heating System	Intermediate	$164,863	94.4167%	$155,658	$155,658	$0	$0
41 - Manatee Temporary Heating System	Peaking	$0	95.5155%	$0	$0	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$9,244,428	95.9309%	$8,868,263	$8,868,263	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$3,633	94.4167%	$3,430	$3,430	$0	$0
45 - 800 MW Unit ESP	Peaking	$113,093	95.5155%	$108,022	$108,022	$0	$0
47 - NPDES Permit Renewal Requirements	Base	$570,169	95.7589%	$545,987	$0	$545,987	$0
47 - NPDES Permit Renewal Requirements	Intermediate	$22,316	94.2474%	$21,032	$0	$21,032	$0
47 - NPDES Permit Renewal Requirements	Peaking	$1,213	95.3443%	$1,157	$0	$1,157	$0
48 - Industrial Boiler MACT	Base	$4,549	95.7589%	$4,356	$0	$4,356	$0
48 - Industrial Boiler MACT	Peaking	$23,884	95.3443%	$22,772	$0	$22,772	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$228,694	95.7589%	$218,994	$0	$218,994	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Peaking	$100	95.3443%	$95	$0	$95	$0
51 - Gopher Tortoise Relocations	Intermediate	$0	94.2474%	$0	$0	$0	$0
51 - Gopher Tortoise Relocations	Peaking	$21,624	95.3443%	$20,617	$0	$20,617	$0
54 - Coal Combustion Residuals	Base	$0	95.7589%	$0	$0	$0	$0
55 - Solar Site Avian Monitoring and Reporting Project	Solar	$128,742	95.9309%	$123,504	$123,504	$0	$0
	Total	$31,093,625		$29,824,876	$15,984,184	$9,584,990	$4,255,702

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

FORM: 42-5A

JANUARY 2019 THROUGH DECEMBER 2019

O&M ACTIVITIES

	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Total
2. Total of O&M Activities	$2,936,281	$2,756,519	$2,865,896	$2,982,781	$2,529,557	$2,596,161	$2,930,778	$2,549,523	$1,876,710	$1,789,852	$2,435,350	$2,844,220	$31,093,625
3. Recoverable Costs Allocated to Energy - Base	$1,115,448	$1,109,851	$1,412,606	$1,564,270	$1,305,191	$1,504,394	$1,370,864	$1,223,958	$435,694	$1,164,982	$1,520,892	$1,272,615	$15,000,765
Recoverable Costs Allocated to Energy - Intermediate	$227,320	$170,145	$73,923	$61,432	$69,670	$96,968	$91,431	$24,020	$86,824	$17,038	$123,705	$216,449	$1,258,925
Recoverable Costs Allocated to Energy - Peaking	$117,304	$57,428	$93,800	$22,865	$90,650	$41,479	$101,033	($34,635)	$73,091	($428,393)	$59,100	$101,178	$294,901
Recoverable Costs Allocated to Energy - Solar	($710)	$9,902	$4,259	$11,979	$22,987	$10,369	$7,687	$8,854	$12,314	$10,907	$3,167	$27,027	$128,742
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$72,686	$220,658	$150,413	$93,281	$29,903	$34,376	$287,990	$75,425	$112,231	$60,646	$49,333	$54,567	$1,241,508
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$155,684	$277,433	$274,685	$11,492	$88,127	$152,265	$38,976	$91,870	$100,256	$27,846	$40,352	$98,390	$1,357,376
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$466,855	$270,012	$265,985	$462,781	$517,663	$375,340	$395,451	$581,298	$475,116	$617,018	$404,728	$519,779	$5,352,024
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$72,513	$101,754	$112,751	($15,790)	$37,222	($8,621)	$25,118	$33,094	$35,029	$32,454	$30,166	$120,000	$575,691
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$101,428	$69,666	$81,148	$105,432	$54,842	$118,696	$122,908	$102,436	$100,868	$41,993	$48,589	$74,248	$1,022,253
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$26,612	$54,023	$78,651	$44,795	$52,721	$38,008	$66,849	$60,996	$51,585	$54,422	$34,439	$42,637	$605,737
5. Recoverable Costs Jurisdictionalized on GCP Demand - Distribution	$581,140	$415,648	$317,674	$620,244	$260,581	$232,886	$422,471	$382,208	$393,701	$190,939	$120,879	$317,331	$4,255,702
6. Retail Production Energy Jurisdictional Factor - Base	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	
Retail Production Energy Jurisdictional Factor - Intermediate	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	
Retail Production Energy Jurisdictional Factor - Peaking	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	
Retail Production Energy Jurisdictional Factor - Solar	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	
7. Retail Distribution Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
Retail Transmission Demand Jurisdictional Factor	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	
Retail Production Demand Jurisdictional Factor - Base	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	
Retail Production Demand Jurisdictional Factor - Intermediate	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	
Retail Production Demand Jurisdictional Factor - Peaking	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	
Retail Production Demand Jurisdictional Factor - Solar	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	
8. Jurisdictional Recoverable Costs- Transmission	$64,841	$196,843	$134,179	$83,213	$26,676	$30,666	$256,907	$67,284	$100,118	$54,101	$44,009	$48,678	$1,107,514
Jurisdictional Recoverable Costs - Production - Base	$1,219,141	$1,330,357	$1,618,161	$1,511,623	$1,336,472	$1,588,986	$1,352,405	$1,262,128	$513,969	$1,144,242	$1,497,645	$1,315,047	$15,690,177
Jurisdictional Recoverable Costs - Production - Intermediate	$654,627	$415,124	$320,480	$494,161	$553,664	$445,303	$459,028	$570,536	$529,761	$597,610	$498,244	$694,242	$6,232,778
Jurisdictional Recoverable Costs - Production - Peaking	$181,180	$151,869	$197,095	$6,785	$122,074	$31,399	$120,451	($1,528)	$103,212	($378,238)	$85,211	$211,054	$830,565
Jurisdictional Recoverable Costs - Production - Solar	$96,445	$76,210	$81,792	$112,452	$74,567	$123,609	$125,070	$106,586	$108,403	$50,675	$49,566	$97,026	$1,102,402
Jurisdictional Recoverable Costs - Distribution	$607,753	$469,671	$396,325	$665,039	$313,302	$270,894	$489,320	$443,203	$445,286	$245,361	$155,318	$359,968	$4,861,440
9. Total Jurisdictional Recoverable Costs for O&M Activities	$2,823,987	$2,640,073	$2,748,033	$2,873,274	$2,426,754	$2,490,857	$2,803,181	$2,448,209	$1,800,749	$1,713,751	$2,329,994	$2,726,015	$29,824,876

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

FORM: 42-6A

JANUARY 2019 THROUGH DECEMBER 2019

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
Capital Projects	ECRC - 2019 Final True-Up (a)	ECRC - 2019 Actual/Estimated (b)	Dif. ECRC - 2019 Actual/Estimated (c)	% Dif. ECRC - 2019 Actual/Estimated (d)
02 - Low NOX Burner Technology	$59,520	$59,721	($200)	(0.34%)
03 - Continuous Emission Monitoring Systems	$479,580	$483,182	($3,601)	(0.75%)
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,608,141	$1,616,659	($8,518)	(0.53%)
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,659	$1,660	($1)	(0.04%)
08 - Oil Spill Clean-up/Response Equipment	$148,654	$196,866	($48,212)	(24.49%)
10 - Relocate Storm Water Runoff	$6,337	$6,370	($34)	(0.53%)
NA-Amortization of Gains on Sales of Emissions Allowances	($34)	($36)	$2	(4.84%)
12 - Scherer Discharge Pipeline	$34,499	$34,674	($176)	(0.51%)
20 - Wastewater Discharge Elimination & Reuse	$41,420	$41,798	($378)	(0.90%)
21 - St. Lucie Turtle Nets	$733,266	$738,541	($5,275)	(0.71%)
22 - Pipeline Integrity Management	$264,940	$266,662	($1,722)	(0.65%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$2,166,010	$2,195,724	($29,714)	(1.35%)
24 - Manatee Reburn	$3,063,843	$3,077,824	($13,981)	(0.45%)
25 - Pt. Everglades ESP Technology	$0	$0	$0	0.00%
26 - UST Remove/Replacement	$6,670	$6,715	($45)	(0.67%)
28 - CWA 316(b) Phase II Rule	$78,084	$98,587	($20,503)	(20.80%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$45,007,607	$45,313,398	($305,791)	(0.67%)
33 - MATS Project	$9,534,820	$9,599,646	($64,826)	(0.68%)
34 - St Lucie Cooling Water System Inspection & Maintenance	$346,650	$353,973	($7,322)	(2.07%)
35 - Martin Plant Drinking Water System Compliance	$18,057	$18,188	($131)	(0.72%)
36 - Low-Level Radioactive Waste Storage	$1,662,849	$1,673,652	($10,803)	(0.65%)
37 - DeSoto Next Generation Solar Energy Center	$12,288,466	$12,369,828	($81,362)	(0.66%)
38 - Space Coast Next Generation Solar Energy Center	$5,711,538	$5,749,305	($37,767)	(0.66%)
39 - Martin Next Generation Solar Energy Center	$34,599,472	$34,871,267	($271,795)	(0.78%)
41 - Manatee Temporary Heating System	$1,277,053	$1,276,656	$396	0.03%
42 - Turkey Point Cooling Canal Monitoring Plan	$5,052,166	$5,149,286	($97,120)	(1.89%)
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$14,683	$14,779	($96)	(0.65%)
45 - 800 MW Unit ESP	$18,881,860	$19,006,233	($124,373)	(0.65%)
47 - NPDES Permit Renewal Requirements	$0	$0	$0	0.00%
50 - Steam Electric Effluent Guidelines Revised Rules	$10,877	$10,373	$504	4.86%
54 - Coal Combustion Residuals	$7,244,199	$7,340,599	($96,400)	(1.31%)
Total	$150,342,885	$151,572,128	($1,229,243)	-0.81%

(a) The 12-Month Totals on Form 42-7A

(b) The approved projected amount in accordance with FPSC Order No. PSC-2019-0500-FOF-EI

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

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

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

FORM: 42-6A

JANUARY 2019 THROUGH DECEMBER 2019
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
	ECRC - 2019 Final True-Up (a)	ECRC - 2019 Actual/Estimated (b)	Dif. ECRC - 2019 Actual/Estimated (c)	% Dif. ECRC - 2019 Actual/Estimated (d)
2. Total Investment Projects - Recoverable Costs	$150,342,885	$151,572,128	$1,229,243	0.82%
3. Recoverable Costs Allocated to Energy	$3,602,909	$3,620,690	$17,781	0.49%
4. Recoverable Costs Allocated to Demand	$146,739,976	$147,951,438	$1,211,462	0.83%
5. Jurisdictional Energy Recoverable Costs	$12,808,696	$12,905,198	$96,502	0.75%
8. Jurisdictional Demand Recoverable Costs	$130,460,594	$131,533,823	$1,073,229	0.82%
9. Total Jurisdictional Recoverable Costs for Investment Projects	$143,269,291	$144,439,021	$1,169,730	0.82%

(a) The 12-Month Totals on Form 42-7A

(b) The approved amount in accordance with FPSC Order No. PSC-2019-0500-FOF-EI

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

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

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

FORM: 42-7A

JANUARY 2019 THROUGH DECEMBER 2019
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Capital Investment Projects [a]	Strata	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
02 - Low NOX Burner Technology	Peaking	$5,021	$5,001	$4,981	$4,961	$4,941	$4,922	$5,001	$4,980	$4,959	$4,939	$4,918	$4,897	$59,520
03 - Continuous Emission Monitoring Systems	Base	$2,379	$2,372	$2,364	$2,357	$2,349	$2,342	$2,398	$2,390	$2,382	$2,374	$2,366	$2,358	$28,428
03 - Continuous Emission Monitoring Systems	Intermediate	$23,606	$23,464	$23,400	$23,335	$23,271	$23,206	$23,772	$23,610	$23,542	$23,474	$23,407	$23,339	$281,424
03 - Continuous Emission Monitoring Systems	Peaking	$14,152	$14,112	$14,072	$14,032	$13,993	$13,953	$14,341	$14,299	$14,257	$14,215	$14,173	$14,131	$169,728
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$142	$142	$142	$142	$142	$142	$150	$150	$150	$150	$150	$150	$1,755
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$51,045	$50,999	$50,992	$50,936	$50,842	$50,875	$53,363	$53,410	$53,456	$54,468	$56,893	$58,629	$635,907
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$19,221	$19,164	$19,106	$19,049	$18,992	$18,935	$19,428	$19,367	$19,307	$19,246	$19,186	$19,125	$230,126
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$62,163	$61,946	$61,728	$61,511	$61,294	$61,077	$62,345	$62,116	$61,887	$61,658	$61,428	$61,199	$740,353
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$143	$142	$141	$140	$139	$139	$138	$137	$136	$135	$135	$134	$1,659
08 - Oil Spill Clean-up/Response Equipment	Distribution	$22	$22	$22	$22	$22	$22	$23	$23	$22	$22	$22	$22	$265
08 - Oil Spill Clean-up/Response Equipment	General	$27	$27	$27	$27	$27	$27	$28	$28	$28	$28	$28	$28	$329
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$6,556	$6,533	$6,510	$6,487	$6,464	$6,442	$6,578	$7,023	$7,574	$8,088	$8,440	$8,439	$85,133
08 - Oil Spill Clean-up/Response Equipment	Peaking	$4,921	$4,903	$4,884	$4,865	$4,847	$4,828	$4,913	$5,219	$5,598	$5,894	$6,038	$6,017	$62,927
10 - Relocate Storm Water Runoff	Base	$527	$526	$525	$523	$522	$520	$536	$534	$533	$531	$530	$528	$6,337
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($2)	($34)
12 - Scherer Discharge Pipeline	Base	$2,876	$2,868	$2,860	$2,852	$2,844	$2,836	$2,915	$2,907	$2,898	$2,890	$2,881	$2,873	$34,499
20 - Wastewater Discharge Elimination & Reuse	Peaking	$3,358	$3,358	$3,358	$3,358	$3,358	$3,358	$3,546	$3,546	$3,546	$3,546	$3,546	$3,546	$41,420
21 - St. Lucie Turtle Nets	Base	$60,249	$60,167	$60,085	$60,003	$59,921	$59,840	$62,383	$62,296	$62,210	$62,124	$62,037	$61,951	$733,266
22 - Pipeline Integrity Management	Intermediate	$11,714	$11,692	$11,671	$11,650	$11,628	$11,607	$12,046	$12,023	$12,001	$11,978	$11,956	$11,933	$141,899
22 - Pipeline Integrity Management	Peaking	$10,160	$10,141	$10,122	$10,104	$10,085	$10,066	$10,444	$10,424	$10,404	$10,384	$10,364	$10,344	$123,041
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$28,852	$28,774	$28,696	$28,619	$28,541	$28,463	$29,288	$29,206	$29,124	$29,042	$28,960	$28,878	$346,440
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$20,703	$20,743	$20,921	$21,079	$21,122	$21,194	$22,312	$22,436	$22,403	$22,370	$22,337	$22,308	$259,927
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$886	$884	$883	$882	$881	$880	$918	$916	$915	$914	$913	$912	$10,784
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$56,344	$56,201	$56,059	$55,917	$55,775	$55,633	$57,342	$57,192	$57,042	$56,892	$56,742	$56,592	$677,731
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$44,659	$44,503	$44,347	$44,190	$44,034	$43,878	$44,787	$44,626	$44,465	$44,685	$45,394	$45,763	$535,331
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$24,097	$24,153	$24,162	$24,161	$24,750	$27,621	$31,188	$31,173	$31,165	$31,129	$31,086	$31,113	$335,797
24 - Manatee Reburn	Peaking	$256,221	$255,496	$254,742	$253,936	$253,129	$252,323	$258,461	$257,610	$256,758	$255,907	$255,055	$254,204	$3,063,843
26 - UST Remove/Replacement	General	$550	$549	$548	$547	$546	$545	$567	$566	$565	$564	$563	$562	$6,670
28 - CWA 316(b) Phase II Rule	Intermediate	$6,438	$6,427	$6,416	$6,405	$6,394	$6,383	$6,633	$6,621	$6,609	$6,598	$6,586	$6,575	$78,084
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$2,968,429	$2,963,538	$2,958,615	$2,953,729	$2,948,885	$2,944,190	$3,059,926	$3,054,929	$3,049,884	$3,045,164	$3,040,446	$3,042,347	$36,030,083
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$104
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$9,369	$9,353	$9,338	$9,323	$9,307	$9,292	$9,660	$9,644	$9,628	$9,611	$9,595	$9,579	$113,698
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$731,838	$730,490	$729,143	$727,795	$726,448	$725,100	$752,376	$750,953	$749,529	$748,106	$746,683	$745,260	$8,863,722
33 - MATS Project	Base	$789,027	$787,142	$785,547	$783,949	$782,358	$780,765	$808,565	$806,844	$805,146	$803,449	$801,752	$800,278	$9,534,820
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$28,104	$28,104	$28,099	$28,099	$28,099	$28,099	$29,675	$29,675	$29,675	$29,675	$29,675	$29,675	$346,650
35 - Martin Plant Drinking Water System Compliance	Intermediate	$667	$667	$667	$667	$808	$947	$983	$981	$979	$977	$975	$973	$10,293
35 - Martin Plant Drinking Water System Compliance	Peaking	$503	$503	$503	$503	$609	$715	$741	$740	$739	$737	$736	$734	$7,765
36 - Low-Level Radioactive Waste Storage	Base	$137,289	$137,037	$136,785	$136,532	$136,280	$136,028	$141,149	$140,883	$140,616	$140,350	$140,083	$139,817	$1,662,849
37 - DeSoto Next Generation Solar Energy Center	Solar	$1,025,803	$1,022,777	$1,019,795	$1,016,790	$1,013,781	$1,010,773	$1,037,810	$1,034,572	$1,031,357	$1,028,164	$1,024,965	$1,021,878	$12,288,466
38 - Space Coast Next Generation Solar Energy Center	Solar	$476,426	$475,050	$473,673	$472,297	$470,921	$469,544	$482,527	$481,091	$479,655	$478,220	$476,784	$475,349	$5,711,538
39 - Martin Next Generation Solar Energy Center	Intermediate	$2,871,716	$2,865,334	$2,859,074	$2,852,962	$2,846,519	$2,840,037	$2,926,601	$2,919,783	$2,913,968	$2,907,729	$2,900,532	$2,895,217	$34,599,472
41 - Manatee Temporary Heating System	Distribution	$1,438	$1,438	$1,438	$1,438	$1,438	$1,438	$1,518	$1,518	$1,518	$1,518	$1,518	$1,518	$17,738
41 - Manatee Temporary Heating System	Intermediate	$73,825	$85,517	$95,519	$97,052	$82,344	$114,034	$102,919	$102,909	$103,169	$103,876	$104,247	$129,114	$1,194,525
41 - Manatee Temporary Heating System	Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$64,790	$64,790
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$388,604	$393,149	$397,771	$400,698	$405,119	$411,293	$435,644	$440,054	$441,105	$442,857	$444,694	$451,180	$5,052,166
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$691	$689	$688	$687	$686	$685	$711	$709	$708	$707	$705	$704	$8,369
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$521	$520	$519	$518	$517	$516	$536	$535	$534	$533	$532	$531	$6,314
45 - 800 MW Unit ESP	Intermediate	$733	$730	$728	$725	$723	$720	$735	$732	$730	$727	$724	$721	$8,728
45 - 800 MW Unit ESP	Peaking	$1,556,380	$1,553,668	$1,550,958	$1,548,248	$1,545,739	$1,543,297	$1,602,969	$1,600,104	$1,597,239	$1,594,374	$1,591,510	$1,588,645	$18,873,132
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$0	$0	$0	$0	$0	$0	$40	$135	$811	$2,006	$2,949	$4,937	$10,877
54 - Coal Combustion Residuals	Base	$403,026	$564,195	$572,690	$586,850	$585,384	$581,618	$621,040	$632,804	$644,993	$657,531	$671,751	$722,316	$7,244,199
	Total	$12,181,422	$12,335,216	$12,335,320	$12,330,960	$12,296,823	$12,311,149	$12,751,972	$12,744,427	$12,735,925	$12,730,560	$12,726,995	$12,862,117	$150,342,885

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

JANUARY 2019 THROUGH DECEMBER 2019

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

Capital Project [a]	Strata	Monthly Data	Jurisdictionalization		Method of Classification	
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	CP Demand	Energy
02 - Low NOX Burner Technology	Peaking	$59,520	95.5155%	$56,851	$0	$56,851
03 - Continuous Emission Monitoring Systems	Base	$28,428	95.9309%	$27,271	$0	$27,271
03 - Continuous Emission Monitoring Systems	Intermediate	$281,424	94.4167%	$265,712	$0	$265,712
03 - Continuous Emission Monitoring Systems	Peaking	$169,728	95.5155%	$162,116	$0	$162,116
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$1,755	95.7589%	$1,681	$1,551	$129
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$635,907	96.9214%	$616,330	$568,920	$47,410
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$230,126	94.2474%	$216,888	$200,204	$16,684
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$740,353	95.3443%	$705,885	$651,586	$54,299
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$1,659	95.7589%	$1,589	$1,467	$122
08 - Oil Spill Clean-up/Response Equipment	Base	$0	95.7589%	$0	$0	$0
08 - Oil Spill Clean-up/Response Equipment	Distribution	$265	100.0000%	$265	$245	$20
08 - Oil Spill Clean-up/Response Equipment	General	$329	96.9214%	$319	$295	$25
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$85,133	94.2474%	$80,236	$74,064	$6,172
08 - Oil Spill Clean-up/Response Equipment	Peaking	$62,927	95.3443%	$59,997	$55,382	$4,615
10 - Relocate Storm Water Runoff	Base	$6,337	95.7589%	$6,068	$5,601	$467
12 - Scherer Discharge Pipeline	Base	$34,499	95.7589%	$33,036	$30,494	$2,541
20 - Wastewater Discharge Elimination & Reuse	Peaking	$41,420	95.3443%	$39,491	$36,454	$3,038
21 - St. Lucie Turtle Nets	Base	$733,266	95.7589%	$702,167	$648,154	$54,013
22 - Pipeline Integrity Management	Intermediate	$141,899	94.2474%	$133,736	$123,448	$10,287
22 - Pipeline Integrity Management	Peaking	$123,041	95.3443%	$117,313	$108,289	$9,024
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$346,440	95.7589%	$331,747	$306,228	$25,519
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$259,927	100.0000%	$259,927	$239,933	$19,994
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$10,784	96.9214%	$10,452	$9,648	$804
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$677,731	94.2474%	$638,744	$589,610	$49,134
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$535,331	95.3443%	$510,408	$471,146	$39,262
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$335,797	89.2071%	$299,555	$276,512	$23,043
24 - Manatee Reburn	Peaking	$3,063,843	95.5155%	$2,926,445	$0	$2,926,445
25 - Pt. Everglades ESP Technology	Intermediate	$0	94.4167%	$0	$0	$0
26 - UST Remove/Replacement	General	$6,670	96.9214%	$6,465	$5,968	$497
28 - CWA 316(b) Phase II Rule	Intermediate	$78,084	94.2474%	$73,592	$67,931	$5,661
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$36,030,083	95.7589%	$34,502,011	$31,848,010	$2,654,001
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$104	100.0000%	$104	$96	$8
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$113,698	94.2474%	$107,157	$98,914	$8,243
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$8,863,722	95.3443%	$8,451,054	$7,800,973	$650,081
33 - MATS Project	Base	$9,534,820	95.7589%	$9,130,439	$8,428,097	$702,341
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$346,650	95.7589%	$331,948	$306,414	$25,534
35 - Martin Plant Drinking Water System Compliance	Intermediate	$10,293	94.2474%	$9,701	$8,954	$746
35 - Martin Plant Drinking Water System Compliance	Peaking	$7,765	95.3443%	$7,403	$6,834	$569
36 - Low-Level Radioactive Waste Storage	Base	$1,662,849	95.7589%	$1,592,326	$1,469,839	$122,487
37 - DeSoto Next Generation Solar Energy Center	Solar	$12,288,466	95.7589%	$11,767,300	$10,862,123	$905,177
38 - Space Coast Next Generation Solar Energy Center	Solar	$5,711,538	95.7589%	$5,469,306	$5,048,590	$420,716
39 - Martin Next Generation Solar Energy Center	Intermediate	$34,599,472	94.2474%	$32,609,103	$30,100,710	$2,508,393
41 - Manatee Temporary Heating System	Distribution	$17,738	100.0000%	$17,738	$16,374	$1,364
41 - Manatee Temporary Heating System	General	$0	96.9214%	$0	$0	$0
41 - Manatee Temporary Heating System	Intermediate	$1,194,525	94.2474%	$1,125,809	$1,039,208	$86,601
41 - Manatee Temporary Heating System	Peaking	$64,790	95.3443%	$61,773	$57,021	$4,752
41 - Manatee Temporary Heating System	Transmission	$0	89.2071%	$0	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$5,052,166	95.7589%	$4,837,899	$4,465,753	$372,146
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$0	94.2474%	$0	$0	$0
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$8,369	94.2474%	$7,888	$7,888	$0
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$6,314	95.3443%	$6,020	$6,020	$0
45 - 800 MW Unit ESP	Intermediate	$8,728	94.2474%	$8,226	$8,226	$0
45 - 800 MW Unit ESP	Peaking	$18,873,132	95.3443%	$17,994,456	$17,994,456	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$10,877	95.7589%	$10,416	$9,615	$801
54 - Coal Combustion Residuals	Base	$7,244,199	95.7589%	$6,936,965	$6,403,352	$533,613
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($34)	95.9309%	($33)	$0	($33)
	Total	$150,342,885		$143,269,291	$130,460,594	$12,808,696

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

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

FORM: 42-7A

JANUARY 2019 THROUGH DECEMBER 2019

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

RAD - ECRC - 42 - 7A - 2	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Twelve Month Amount
2. Total of Capital Investment Projects	$12,181,422	$12,335,216	$12,335,320	$12,330,960	$12,296,823	$12,311,149	$12,751,972	$12,744,427	$12,735,925	$12,730,560	$12,726,995	$12,862,117	$150,342,885
3. Recoverable Costs Jurisdictionalized on Energy - Base	$2,376	$2,369	$2,361	$2,354	$2,346	$2,338	$2,394	$2,387	$2,379	$2,371	$2,364	$2,356	$28,394
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$23,606	$23,464	$23,400	$23,335	$23,271	$23,206	$23,772	$23,610	$23,542	$23,474	$23,407	$23,339	$281,425
Recoverable Costs Jurisdictionalized on Energy - Peaking	$275,393	$274,609	$273,795	$272,929	$272,064	$271,198	$277,803	$276,889	$275,974	$275,060	$274,146	$273,231	$3,293,091
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$24,097	$24,153	$24,162	$24,161	$24,750	$27,621	$31,188	$31,173	$31,165	$31,129	$31,086	$31,113	$335,797
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$4,807,268	$4,965,784	$4,971,954	$4,982,136	$4,978,235	$4,973,931	$5,191,448	$5,200,553	$5,207,282	$5,215,903	$5,226,042	$5,285,062	$61,005,599
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$3,057,272	$3,062,309	$3,065,777	$3,060,924	$3,039,641	$3,064,714	$3,143,634	$3,136,984	$3,131,713	$3,126,428	$3,119,688	$3,138,973	$37,148,057
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$2,414,503	$2,410,032	$2,405,563	$2,401,094	$2,396,930	$2,392,835	$2,482,657	$2,478,262	$2,473,941	$2,469,917	$2,466,231	$2,526,829	$29,318,794
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$1,502,229	$1,497,827	$1,493,468	$1,489,087	$1,484,702	$1,480,317	$1,520,337	$1,515,663	$1,511,013	$1,506,384	$1,501,750	$1,497,227	$18,000,004
Recoverable Costs Jurisdicitionalized on 12 CP Demand - General	$52,507	$52,459	$52,450	$52,392	$52,296	$52,327	$54,875	$54,920	$54,963	$55,974	$58,396	$60,130	$653,690
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$22,171	$22,211	$22,389	$22,547	$22,590	$22,662	$23,862	$23,986	$23,953	$23,920	$23,886	$23,857	$278,034
5. Retail Production Energy Jurisdictional Factor - Base	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	95.93090%	
Retail Production Energy Jurisdictional Factor - Intermediate	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	94.41670%	
Retail Production Energy Jurisdictional Factor - Peaking	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	95.51550%	
6. Retail Transmission Demand Jurisdictional Factor	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	89.20710%	
Retail Production Demand Jurisdictional Factor - Base	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	
Retail Production Demand Jurisdictional Factor - Intermediate	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	94.24740%	
Retail Production Demand Jurisdictional Factor - Peaking	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	95.34430%	
Retail Production Demand Jurisdictional Factor - Solar	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	95.75890%	
Retail Production Demand Jurisdictional Factor - General	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	96.92140%	
Retail Distribution Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7 .Jurisdictional Recoverable Costs - Transmission	$21,496	$21,546	$21,555	$21,553	$22,078	$24,640	$27,822	$27,809	$27,801	$27,769	$27,731	$27,755	$299,555
Jurisdictional Recoverable Costs - Production - Base	$4,605,667	$4,757,452	$4,763,354	$4,773,097	$4,769,353	$4,765,225	$4,973,570	$4,982,282	$4,988,718	$4,996,966	$5,006,668	$5,063,178	$58,445,529
Jurisdictional Recoverable Costs - Production - Intermediate	$2,903,687	$2,908,300	$2,911,508	$2,906,874	$2,886,754	$2,910,323	$2,985,238	$2,978,817	$2,973,786	$2,968,741	$2,962,325	$2,980,436	$35,276,790
Jurisdictional Recoverable Costs - Production - Peaking	$2,565,134	$2,560,122	$2,555,084	$2,549,996	$2,545,199	$2,540,468	$2,632,417	$2,627,353	$2,622,360	$2,617,650	$2,613,262	$2,670,165	$31,099,211
Jurisdictional Recoverable Costs - Production - Solar	$1,438,518	$1,434,303	$1,430,129	$1,425,933	$1,421,734	$1,417,536	$1,455,858	$1,451,382	$1,446,929	$1,442,497	$1,438,059	$1,433,728	$17,236,606
Jurisdictional Recoverable Costs - General	$50,891	$50,844	$50,835	$50,779	$50,686	$50,716	$53,186	$53,229	$53,271	$54,251	$56,598	$58,279	$633,565
Jurisdictional Recoverable Costs - Distribution	$22,171	$22,211	$22,389	$22,547	$22,590	$22,662	$23,862	$23,986	$23,953	$23,920	$23,886	$23,857	$278,034
8. Total Jurisdictional Recoverable Costs for Capital Investment Activities	$11,607,563	$11,754,779	$11,754,854	$11,750,779	$11,718,395	$11,731,570	$12,151,954	$12,144,859	$12,136,818	$12,131,793	$12,128,530	$12,257,398	$143,269,291

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

FORM: 42-8A

JANUARY 2019 THROUGH DECEMBER 2019

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
02 - Low NOX Burner Technology														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3a. Less: Accumulated Depreciation	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
3b. Less: Capital Recovery Unamortized Balance	($300,662)	($297,530)	($294,398)	($291,266)	($288,134)	($285,002)	($281,871)	($278,739)	($275,607)	($272,475)	($269,343)	($266,211)	($263,079)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$300,662	$297,530	$294,398	$291,267	$288,135	$285,003	$281,871	$278,739	$275,607	$272,475	$269,343	$266,211	$263,079	
6. Average Net Investment		$299,096	$295,964	$292,833	$289,701	$286,569	$283,437	$280,305	$277,173	$274,041	$270,909	$267,777	$264,645	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,557	$1,541	$1,525	$1,508	$1,492	$1,476	$1,554	$1,536	$1,519	$1,502	$1,484	$1,467	$18,161
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$331	$328	$324	$321	$318	$314	$316	$312	$308	$305	$301	$298	$3,777
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$37,583
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$5,021	$5,001	$4,981	$4,961	$4,941	$4,922	$5,001	$4,980	$4,959	$4,939	$4,918	$4,897	$59,520

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8A

JANUARY 2019 THROUGH DECEMBER 2019

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
03 - Continuous Emission Monitoring Systems														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	
3a. Less: Accumulated Depreciation	$372,862	$391,912	$393,111	$394,309	$395,508	$396,707	$397,906	$399,105	$400,304	$401,503	$402,702	$403,901	$405,100	
3b. Less: Capital Recovery Unamortized Balance	($44,752)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$187,543	$186,344	$185,146	$183,947	$182,748	$181,549	$180,350	$179,151	$177,952	$176,753	$175,554	$174,355	$173,157	
6. Average Net Investment		$186,944	$185,745	$184,546	$183,347	$182,148	$180,949	$179,750	$178,552	$177,353	$176,154	$174,955	$173,756	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$973	$967	$961	$955	$948	$942	$996	$990	$983	$976	$970	$963	$11,625
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$207	$206	$204	$203	$202	$201	$202	$201	$200	$198	$197	$196	$2,417
8. Investment Expenses														
a. Depreciation (e)		$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$14,387
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,379	$2,372	$2,364	$2,357	$2,349	$2,342	$2,398	$2,390	$2,382	$2,374	$2,366	$2,358	$28,428

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8A

JANUARY 2019 THROUGH DECEMBER 2019

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
03 - Continuous Emission Monitoring Systems														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($15,886)	$0	$0	$0	$0	$0	($18,573)	$0	$0	$0	$0	$0	($34,459)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		($1,613)	$0	$0	$0	$0	$0	$2,063	$1	$0	$0	$0	$0	$450
2. Plant-In-Service/Depreciation Base (b)	$2,324,626	$2,307,127	$2,307,127	$2,307,127	$2,307,127	$2,307,127	$2,307,127	$2,290,616	$2,290,617	$2,290,617	$2,290,617	$2,290,617	$2,290,617	
3a. Less: Accumulated Depreciation	$427,767	$433,982	$441,783	$449,584	$457,385	$465,186	$472,987	$482,818	$490,555	$498,291	$506,027	$513,763	$521,499	
3b. Less: Capital Recovery Unamortized Balance	($232,063)	($229,646)	($227,229)	($224,811)	($222,394)	($219,977)	($217,559)	($215,142)	($212,725)	($210,307)	($207,890)	($205,473)	($203,055)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,128,922	$2,102,791	$2,092,572	$2,082,354	$2,072,136	$2,061,918	$2,051,699	$2,022,940	$2,012,787	$2,002,634	$1,992,481	$1,982,327	$1,972,174	
6. Average Net Investment		$2,115,856	$2,097,682	$2,087,463	$2,077,245	$2,067,027	$2,056,808	$2,037,320	$2,017,864	$2,007,710	$1,997,557	$1,987,404	$1,977,251	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$11,016	$10,921	$10,868	$10,815	$10,762	$10,709	$11,293	$11,185	$11,129	$11,073	$11,016	$10,960	$131,747
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,345	$2,324	$2,313	$2,302	$2,290	$2,279	$2,293	$2,271	$2,260	$2,248	$2,237	$2,226	$27,389
8. Investment Expenses														
a. Depreciation (e)		$7,828	$7,801	$7,801	$7,801	$7,801	$7,801	$7,768	$7,736	$7,736	$7,736	$7,736	$7,736	$93,281
b. Amortization (f)		$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$29,008
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$23,606	$23,464	$23,400	$23,335	$23,271	$23,206	$23,772	$23,610	$23,542	$23,474	$23,407	$23,339	$281,424

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
03 - Continuous Emission Monitoring Systems														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	
3a. Less: Accumulated Depreciation	$122,435	$126,971	$131,508	$136,044	$140,581	$145,117	$149,654	$154,190	$158,727	$163,264	$167,800	$172,337	$176,873	
3b. Less: Capital Recovery Unamortized Balance	($168,529)	($166,774)	($165,018)	($163,263)	($161,507)	($159,752)	($157,996)	($156,241)	($154,485)	($152,730)	($150,974)	($149,219)	($147,463)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,247,818	$1,241,526	$1,235,234	$1,228,942	$1,222,650	$1,216,358	$1,210,066	$1,203,774	$1,197,482	$1,191,190	$1,184,898	$1,178,606	$1,172,313	
6. Average Net Investment		$1,244,672	$1,238,380	$1,232,088	$1,225,796	$1,219,504	$1,213,212	$1,206,920	$1,200,628	$1,194,336	$1,188,044	$1,181,752	$1,175,459	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,480	$6,448	$6,415	$6,382	$6,349	$6,316	$6,690	$6,655	$6,620	$6,585	$6,551	$6,516	$78,007
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,379	$1,372	$1,365	$1,358	$1,351	$1,344	$1,359	$1,351	$1,344	$1,337	$1,330	$1,323	$16,216
8. Investment Expenses														
a. Depreciation (e)		$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$54,439
b. Amortization (f)		$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$21,066
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$14,152	$14,112	$14,072	$14,032	$13,993	$13,953	$14,341	$14,299	$14,257	$14,215	$14,173	$14,131	$169,728

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3a. Less: Accumulated Depreciation	$21,854	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3b. Less: Capital Recovery Unamortized Balance	($44,384)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	
6. Average Net Investment		$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$117	$117	$117	$117	$117	$117	$125	$125	$125	$125	$125	$125	$1,453
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$25	$302
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$142	$142	$142	$142	$142	$142	$150	$150	$150	$150	$150	$150	$1,755

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$12,372	($15,382)	$0	$25,156	$2,646	$26,009	$2,267	$316,015	$425,704	$109,633	$904,419
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	
3a. Less: Accumulated Depreciation	$384,568	$391,865	$399,162	$406,460	$413,757	$421,054	$428,352	$435,649	$442,946	$450,243	$457,541	$464,838	$472,135	
4. CWIP Non-Interest Bearing	$1,478,493	$1,478,493	$1,478,493	$1,490,865	$1,475,483	$1,475,483	$1,500,639	$1,503,285	$1,529,294	$1,531,560	$1,847,576	$2,273,279	$2,382,912	
5. Net Investment (Lines 2 - 3 + 4)	$6,931,765	$6,924,468	$6,917,170	$6,922,245	$6,899,566	$6,892,269	$6,910,127	$6,905,476	$6,924,188	$6,919,157	$7,227,875	$7,646,281	$7,748,617	
6. Average Net Investment		$6,928,116	$6,920,819	$6,919,708	$6,910,906	$6,895,918	$6,901,198	$6,907,802	$6,914,832	$6,921,672	$7,073,516	$7,437,078	$7,697,449	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$36,071	$36,033	$36,027	$35,981	$35,903	$35,930	$38,290	$38,329	$38,367	$39,209	$41,224	$42,667	$454,032
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$7,677	$7,669	$7,668	$7,658	$7,641	$7,647	$7,775	$7,783	$7,791	$7,962	$8,371	$8,664	$94,307
8. Investment Expenses														
a. Depreciation (e)		$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$87,568
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$51,045	$50,999	$50,992	$50,936	$50,842	$50,875	$53,363	$53,410	$53,456	$54,468	$56,893	$58,629	$635,907

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	
3a. Less: Accumulated Depreciation	$975,252	$981,219	$987,186	$993,153	$999,121	$1,005,088	$1,011,055	$1,017,022	$1,022,989	$1,028,956	$1,034,923	$1,040,890	$1,046,857	
3b. Less: Capital Recovery Unamortized Balance	($297,029)	($293,928)	($290,827)	($287,726)	($284,625)	($281,524)	($278,423)	($275,322)	($272,221)	($269,120)	($266,019)	($262,918)	($259,817)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,612,409	$1,603,341	$1,594,273	$1,585,205	$1,576,137	$1,567,068	$1,558,000	$1,548,932	$1,539,864	$1,530,796	$1,521,728	$1,512,660	$1,503,592	
6. Average Net Investment		$1,607,875	$1,598,807	$1,589,739	$1,580,671	$1,571,602	$1,562,534	$1,553,466	$1,544,398	$1,535,330	$1,526,262	$1,517,194	$1,508,126	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$8,371	$8,324	$8,277	$8,230	$8,182	$8,135	$8,611	$8,561	$8,510	$8,460	$8,410	$8,360	$100,431
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,782	$1,772	$1,762	$1,752	$1,741	$1,731	$1,749	$1,738	$1,728	$1,718	$1,708	$1,698	$20,878
8. Investment Expenses														
a. Depreciation (e)		$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$71,605
b. Amortization (f)		$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$37,212
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$19,221	$19,164	$19,106	$19,049	$18,992	$18,935	$19,428	$19,367	$19,307	$19,246	$19,186	$19,125	$230,126

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	
3a. Less: Accumulated Depreciation	$1,327,497	$1,338,673	$1,349,848	$1,361,024	$1,372,199	$1,383,374	$1,394,550	$1,405,725	$1,416,901	$1,428,076	$1,439,252	$1,450,427	$1,461,603	
3b. Less: Capital Recovery Unamortized Balance	($2,228,226)	($2,205,023)	($2,181,820)	($2,158,618)	($2,135,415)	($2,112,212)	($2,089,009)	($2,065,806)	($2,042,604)	($2,019,401)	($1,996,198)	($1,972,995)	($1,949,792)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,417,279	$4,382,901	$4,348,523	$4,314,144	$4,279,766	$4,245,388	$4,211,010	$4,176,631	$4,142,253	$4,107,875	$4,073,497	$4,039,118	$4,004,740	
6. Average Net Investment		$4,400,090	$4,365,712	$4,331,333	$4,296,955	$4,262,577	$4,228,199	$4,193,820	$4,159,442	$4,125,064	$4,090,686	$4,056,307	$4,021,929	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$22,909	$22,730	$22,551	$22,372	$22,193	$22,014	$23,247	$23,056	$22,865	$22,675	$22,484	$22,294	$271,388
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$4,876	$4,838	$4,800	$4,761	$4,723	$4,685	$4,721	$4,682	$4,643	$4,604	$4,566	$4,527	$56,426
8. Investment Expenses														
a. Depreciation (e)		$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$134,105
b. Amortization (f)		$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$278,434
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$62,163	$61,946	$61,728	$61,511	$61,294	$61,077	$62,345	$62,116	$61,887	$61,658	$61,428	$61,199	$740,353

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	
3a. Less: Accumulated Depreciation	$29,283	$29,415	$29,547	$29,680	$29,812	$29,944	$30,076	$30,208	$30,340	$30,472	$30,605	$30,737	$30,869	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,747	$1,615	$1,483	$1,350	$1,218	$1,086	$954	$822	$690	$558	$425	$293	$161	
6. Average Net Investment		$1,681	$1,549	$1,417	$1,284	$1,152	$1,020	$888	$756	$624	$492	$359	$227	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$9	$8	$7	$7	$6	$5	$5	$4	$3	$3	$2	$1	$61
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2	$2	$2	$1	$1	$1	$1	$1	$1	$1	$0	$0	$13
8. Investment Expenses														
a. Depreciation (e)		$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$1,586
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$143	$142	$141	$140	$139	$139	$138	$137	$136	$135	$135	$134	$1,659

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	
3a. Less: Accumulated Depreciation	$329	$334	$339	$344	$349	$354	$359	$364	$369	$374	$379	$384	$389	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,667	$2,662	$2,657	$2,652	$2,647	$2,642	$2,637	$2,632	$2,627	$2,622	$2,617	$2,612	$2,607	
6. Average Net Investment		$2,664	$2,659	$2,654	$2,649	$2,644	$2,639	$2,634	$2,629	$2,624	$2,619	$2,614	$2,609	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$14	$14	$14	$14	$14	$14	$15	$15	$15	$15	$14	$14	$170
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$35
8. Investment Expenses														
a. Depreciation (e)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$60
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$22	$22	$22	$22	$22	$22	$23	$23	$22	$22	$22	$22	$265

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	
3a. Less: Accumulated Depreciation	$1,003	$1,009	$1,014	$1,020	$1,025	$1,031	$1,036	$1,042	$1,047	$1,053	$1,058	$1,064	$1,069	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,410	$3,404	$3,399	$3,393	$3,388	$3,382	$3,377	$3,371	$3,365	$3,360	$3,354	$3,349	$3,343	
6. Average Net Investment		$3,407	$3,401	$3,396	$3,390	$3,385	$3,379	$3,374	$3,368	$3,363	$3,357	$3,352	$3,346	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$18	$18	$18	$18	$18	$18	$19	$19	$19	$19	$19	$19	$218
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$45
8. Investment Expenses														
a. Depreciation (e)		$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$66
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$27	$27	$27	$27	$27	$27	$28	$28	$28	$28	$28	$28	$329

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$545	$10,689	$33,013	$38,755	$720	($6,154)	$77,568
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$37,050	$0	$26,050	($8,858)	$22,550	$76,792
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($8,858)	$0	($8,858)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$438,787	$438,787	$438,787	$438,787	$438,787	$438,787	$438,787	$438,787	$475,837	$475,837	$501,887	$493,030	$515,580	
3a. Less: Accumulated Depreciation	($29,508)	($25,895)	($22,282)	($18,669)	($15,056)	($11,443)	($7,831)	($4,218)	($296)	$3,934	$8,382	$4,136	$8,720	
3b. Less: Capital Recovery Unamortized Balance	$176	$174	$172	$170	$168	$167	$165	$163	$161	$159	$157	$156	$154	
4. CWIP Non-Interest Bearing	$4	$4	$4	$4	$4	$4	$4	$548	$11,237	$44,251	$83,005	$83,725	$77,572	
5. Net Investment (Lines 2 - 3 + 4)	$468,123	$464,512	$460,901	$457,290	$453,679	$450,068	$446,457	$443,391	$487,210	$515,995	$576,354	$572,464	$584,278	
6. Average Net Investment		$466,317	$462,706	$459,095	$455,484	$451,873	$448,262	$444,924	$465,300	$501,602	$546,174	$574,409	$578,371	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$2,428	$2,409	$2,390	$2,371	$2,353	$2,334	$2,466	$2,579	$2,780	$3,027	$3,184	$3,206	$31,528
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$517	$513	$509	$505	$501	$497	$501	$524	$565	$615	$647	$651	$6,542
8. Investment Expenses														
a. Depreciation (e)		$3,613	$3,613	$3,613	$3,613	$3,613	$3,613	$3,613	$3,922	$4,230	$4,447	$4,612	$4,584	$47,085
b. Amortization (f)		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($22)
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$6,556	$6,533	$6,510	$6,487	$6,464	$6,442	$6,578	$7,023	$7,574	$8,088	$8,440	$8,439	$85,133

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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08 - Oil Spill Clean-up/Response Equipment														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$22,550	$4,261	$0	$23,119	$49,930
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$27,950	$0	$19,652	($12,489)	$0	$35,112
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12,489)	$0	($12,489)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$419,360	$419,360	$419,360	$419,360	$419,360	$419,360	$419,360	$419,360	$447,310	$447,310	$466,961	$454,472	$454,472	
3a. Less: Accumulated Depreciation	$106,384	$109,338	$112,292	$115,247	$118,201	$121,155	$124,109	$127,063	$130,251	$133,671	$137,255	$128,438	$132,037	
4. CWIP Non-Interest Bearing	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	$22,546	$26,807	$26,807	$49,927	
5. Net Investment (Lines 2 - 3 + 4)	$312,972	$310,018	$307,064	$304,109	$301,155	$298,201	$295,247	$292,292	$317,055	$336,185	$356,514	$352,841	$372,361	
6. Average Net Investment		$311,495	$308,541	$305,586	$302,632	$299,678	$296,724	$293,770	$304,674	$326,620	$346,350	$354,677	$362,601	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,622	$1,606	$1,591	$1,576	$1,560	$1,545	$1,628	$1,689	$1,810	$1,920	$1,966	$2,010	$20,523
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$345	$342	$339	$335	$332	$329	$331	$343	$368	$390	$399	$408	$4,260
8. Investment Expenses														
a. Depreciation (e)		$2,954	$2,954	$2,954	$2,954	$2,954	$2,954	$2,954	$3,187	$3,420	$3,584	$3,673	$3,599	$38,143
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$4,921	$4,903	$4,884	$4,865	$4,847	$4,828	$4,913	$5,219	$5,598	$5,894	$6,038	$6,017	$62,927

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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10 - Relocate Storm Water Runoff														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	
3a. Less: Accumulated Depreciation	$69,128	$69,349	$69,570	$69,791	$70,011	$70,232	$70,453	$70,674	$70,895	$71,116	$71,337	$71,557	$71,778	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$48,666	$48,445	$48,224	$48,003	$47,782	$47,562	$47,341	$47,120	$46,899	$46,678	$46,457	$46,236	$46,016	
6. Average Net Investment		$48,555	$48,335	$48,114	$47,893	$47,672	$47,451	$47,230	$47,009	$46,789	$46,568	$46,347	$46,126	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$253	$252	$250	$249	$248	$247	$262	$261	$259	$258	$257	$256	$3,052
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$54	$54	$53	$53	$53	$53	$53	$53	$53	$52	$52	$52	$634
8. Investment Expenses														
a. Depreciation (e)		$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$2,650
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$527	$526	$525	$523	$522	$520	$536	$534	$533	$531	$530	$528	$6,337

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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12 - Scherer Discharge Pipeline														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	
3a. Less: Accumulated Depreciation	$599,758	$601,031	$602,303	$603,576	$604,848	$606,121	$607,394	$608,666	$609,939	$611,211	$612,484	$613,757	$615,029	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$254,566	$253,293	$252,020	$250,748	$249,475	$248,203	$246,930	$245,657	$244,385	$243,112	$241,840	$240,567	$239,294	
6. Average Net Investment		$253,929	$252,657	$251,384	$250,112	$248,839	$247,566	$246,294	$245,021	$243,749	$242,476	$241,203	$239,931	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,322	$1,315	$1,309	$1,302	$1,296	$1,289	$1,365	$1,358	$1,351	$1,344	$1,337	$1,330	$15,918
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$281	$280	$279	$277	$276	$274	$277	$276	$274	$273	$271	$270	$3,309
8. Investment Expenses														
a. Depreciation (e)		$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$15,271
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,876	$2,868	$2,860	$2,852	$2,844	$2,836	$2,915	$2,907	$2,898	$2,890	$2,881	$2,873	$34,499

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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20 - Wastewater Discharge Elimination & Reuse														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3a. Less: Accumulated Depreciation	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	
6. Average Net Investment		$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$2,768	$2,768	$2,768	$2,768	$2,768	$2,768	$2,947	$2,947	$2,947	$2,947	$2,947	$2,947	$34,294
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$589	$589	$589	$589	$589	$589	$598	$598	$598	$598	$598	$598	$7,126
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$3,358	$3,358	$3,358	$3,358	$3,358	$3,358	$3,546	$3,546	$3,546	$3,546	$3,546	$3,546	$41,420

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
21 - St. Lucie Turtle Nets														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	
3a. Less: Accumulated Depreciation	($586,541)	($573,586)	($560,631)	($547,675)	($534,720)	($521,764)	($508,809)	($495,853)	($482,898)	($469,943)	($456,987)	($444,032)	($431,076)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,496,100	$7,483,145	$7,470,189	$7,457,234	$7,444,278	$7,431,323	$7,418,367	$7,405,412	$7,392,457	$7,379,501	$7,366,546	$7,353,590	$7,340,635	
6. Average Net Investment		$7,489,622	$7,476,667	$7,463,711	$7,450,756	$7,437,801	$7,424,845	$7,411,890	$7,398,934	$7,385,979	$7,373,023	$7,360,068	$7,347,113	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$38,994	$38,927	$38,859	$38,792	$38,724	$38,657	$41,085	$41,013	$40,941	$40,869	$40,797	$40,725	$478,382
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$8,299	$8,285	$8,271	$8,256	$8,242	$8,227	$8,343	$8,328	$8,314	$8,299	$8,284	$8,270	$99,418
8. Investment Expenses														
a. Depreciation (e)		$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$155,465
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$60,249	$60,167	$60,085	$60,003	$59,921	$59,840	$62,383	$62,296	$62,210	$62,124	$62,037	$61,951	$733,266

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
22 - Pipeline Integrity Management														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	
3a. Less: Accumulated Depreciation	$222,522	$225,900	$229,278	$232,656	$236,034	$239,412	$242,790	$246,168	$249,546	$252,924	$256,303	$259,681	$263,059	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,321,740	$1,318,362	$1,314,984	$1,311,605	$1,308,227	$1,304,849	$1,301,471	$1,298,093	$1,294,715	$1,291,337	$1,287,959	$1,284,581	$1,281,203	
6. Average Net Investment		$1,320,051	$1,316,673	$1,313,294	$1,309,916	$1,306,538	$1,303,160	$1,299,782	$1,296,404	$1,293,026	$1,289,648	$1,286,270	$1,282,892	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,873	$6,855	$6,838	$6,820	$6,802	$6,785	$7,205	$7,186	$7,167	$7,149	$7,130	$7,111	$83,920
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,463	$1,459	$1,455	$1,452	$1,448	$1,444	$1,463	$1,459	$1,455	$1,452	$1,448	$1,444	$17,442
8. Investment Expenses														
a. Depreciation (e)		$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$40,537
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$11,714	$11,692	$11,671	$11,650	$11,628	$11,607	$12,046	$12,023	$12,001	$11,978	$11,956	$11,933	$141,899

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
22 - Pipeline Integrity Management														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	
3a. Less: Accumulated Depreciation	$190,031	$193,011	$195,992	$198,972	$201,953	$204,933	$207,914	$210,894	$213,874	$216,855	$219,835	$222,816	$225,796	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,138,499	$1,135,518	$1,132,538	$1,129,558	$1,126,577	$1,123,597	$1,120,616	$1,117,636	$1,114,655	$1,111,675	$1,108,694	$1,105,714	$1,102,734	
6. Average Net Investment		$1,137,009	$1,134,028	$1,131,048	$1,128,067	$1,125,087	$1,122,106	$1,119,126	$1,116,146	$1,113,165	$1,110,185	$1,107,204	$1,104,224	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5,920	$5,904	$5,889	$5,873	$5,858	$5,842	$6,203	$6,187	$6,170	$6,154	$6,137	$6,121	$72,258
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,260	$1,257	$1,253	$1,250	$1,247	$1,243	$1,260	$1,256	$1,253	$1,250	$1,246	$1,243	$15,018
8. Investment Expenses														
a. Depreciation (e)		$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$35,765
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$10,160	$10,141	$10,122	$10,104	$10,085	$10,066	$10,444	$10,424	$10,404	$10,384	$10,364	$10,344	$123,041

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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23 - SPCC - Spill Prevention, Control & Countermeasures														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	
3a. Less: Accumulated Depreciation	$618,217	$630,518	$642,819	$655,119	$667,420	$679,721	$692,022	$704,323	$716,624	$728,924	$741,225	$753,526	$765,827	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,627,218	$2,614,917	$2,602,616	$2,590,315	$2,578,014	$2,565,714	$2,553,413	$2,541,112	$2,528,811	$2,516,510	$2,504,209	$2,491,908	$2,479,608	
6. Average Net Investment		$2,621,067	$2,608,766	$2,596,466	$2,584,165	$2,571,864	$2,559,563	$2,547,262	$2,534,961	$2,522,661	$2,510,360	$2,498,059	$2,485,758	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$13,646	$13,582	$13,518	$13,454	$13,390	$13,326	$14,120	$14,051	$13,983	$13,915	$13,847	$13,779	$164,612
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,904	$2,891	$2,877	$2,864	$2,850	$2,836	$2,867	$2,853	$2,840	$2,826	$2,812	$2,798	$34,217
8. Investment Expenses														
a. Depreciation (e)		$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$147,610
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$28,852	$28,774	$28,696	$28,619	$28,541	$28,463	$29,288	$29,206	$29,124	$29,042	$28,960	$28,878	$346,440

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	($10,962)	$43,669	$16,183	$7,379	$25,463	$47,036	$0	$0	$0	$0	($5,647)	$123,120
b. Clearings to Plant		$0	$27,343	$0	$0	$0	$0	$55	$0	$0	$0	$0	$5,647	$33,045
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,373,917	$3,373,917	$3,401,260	$3,401,260	$3,401,260	$3,401,260	$3,401,260	$3,401,315	$3,401,315	$3,401,315	$3,401,315	$3,401,315	$3,406,962	
3a. Less: Accumulated Depreciation	$921,374	$926,309	$931,264	$936,239	$941,214	$946,189	$951,163	$956,138	$961,113	$966,088	$971,063	$976,038	$981,017	
4. CWIP Non-Interest Bearing	$46,963	$46,963	$36,002	$79,670	$95,853	$103,232	$128,694	$175,730	$175,730	$175,730	$175,730	$175,730	$170,083	
5. Net Investment (Lines 2 - 3 + 4)	$2,499,506	$2,494,571	$2,505,998	$2,544,691	$2,555,899	$2,558,303	$2,578,791	$2,620,907	$2,615,932	$2,610,957	$2,605,982	$2,601,007	$2,596,028	
6. Average Net Investment		$2,497,039	$2,500,284	$2,525,344	$2,550,295	$2,557,101	$2,568,547	$2,599,849	$2,618,419	$2,613,444	$2,608,469	$2,603,494	$2,598,517	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$13,001	$13,017	$13,148	$13,278	$13,313	$13,373	$14,411	$14,514	$14,486	$14,459	$14,431	$14,404	$165,836
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,767	$2,771	$2,798	$2,826	$2,834	$2,846	$2,926	$2,947	$2,942	$2,936	$2,930	$2,925	$34,448
8. Investment Expenses														
a. Depreciation (e)		$4,935	$4,955	$4,975	$4,975	$4,975	$4,975	$4,975	$4,975	$4,975	$4,975	$4,975	$4,979	$59,643
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$20,703	$20,743	$20,921	$21,079	$21,122	$21,194	$22,312	$22,436	$22,403	$22,370	$22,337	$22,308	$259,927

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	
3a. Less: Accumulated Depreciation	$35,393	$35,576	$35,759	$35,943	$36,126	$36,309	$36,493	$36,676	$36,859	$37,043	$37,226	$37,409	$37,593	
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)	$111,299	$111,115	$110,932	$110,749	$110,565	$110,382	$110,199	$110,015	$109,832	$109,649	$109,465	$109,282	$109,098	
6. Average Net Investment		$111,207	$111,024	$110,840	$110,657	$110,474	$110,290	$110,107	$109,924	$109,740	$109,557	$109,374	$109,190	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$579	$578	$577	$576	$575	$574	$610	$609	$608	$607	$606	$605	$7,106
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$123	$123	$123	$123	$122	$122	$124	$124	$124	$123	$123	$123	$1,477
8. Investment Expenses														
a. Depreciation (e)		$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$2,200
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$886	$884	$883	$882	$881	$880	$918	$916	$915	$914	$913	$912	$10,784

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,983,517	$4,983,517	$4,983,517	$4,983,517	$4,983,517	$4,983,517	$4,983,517	$4,983,517	$4,983,517	$4,983,517	$4,983,517	$4,983,517	$4,983,517	
3a. Less: Accumulated Depreciation	$627,776	$639,657	$651,538	$663,420	$675,301	$687,183	$699,064	$710,945	$722,827	$734,708	$746,590	$758,471	$770,353	
3b. Less: Capital Recovery Unamortized Balance	($1,015,825)	($1,005,211)	($994,596)	($983,982)	($973,368)	($962,753)	($952,139)	($941,525)	($930,910)	($920,296)	($909,682)	($899,067)	($888,453)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$5,371,566	$5,349,070	$5,326,575	$5,304,079	$5,281,583	$5,259,087	$5,236,592	$5,214,096	$5,191,600	$5,169,104	$5,146,609	$5,124,113	$5,101,617	
6. Average Net Investment		$5,360,318	$5,337,823	$5,315,327	$5,292,831	$5,270,335	$5,247,839	$5,225,344	$5,202,848	$5,180,352	$5,157,856	$5,135,361	$5,112,865	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$27,908	$27,791	$27,674	$27,557	$27,440	$27,322	$28,964	$28,840	$28,715	$28,590	$28,466	$28,341	$337,607
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$5,940	$5,915	$5,890	$5,865	$5,840	$5,815	$5,882	$5,856	$5,831	$5,806	$5,780	$5,755	$70,175
8. Investment Expenses														
a. Depreciation (e)		$11,881	$11,881	$11,881	$11,881	$11,881	$11,881	$11,881	$11,881	$11,881	$11,881	$11,881	$11,881	$142,577
b. Amortization (f)		$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$127,372
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$56,344	$56,201	$56,059	$55,917	$55,775	$55,633	$57,342	$57,192	$57,042	$56,892	$56,742	$56,592	$677,731

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$156	$932	$198	$115,244	$146,864	$13,320	$276,713
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	
3a. Less: Accumulated Depreciation	$1,165,236	$1,176,938	$1,188,640	$1,200,342	$1,212,044	$1,223,746	$1,235,448	$1,247,149	$1,258,851	$1,270,553	$1,282,255	$1,293,957	$1,305,659	
3b. Less: Capital Recovery Unamortized Balance	($1,254,179)	($1,241,148)	($1,228,116)	($1,215,085)	($1,202,053)	($1,189,022)	($1,175,990)	($1,162,959)	($1,149,927)	($1,136,896)	($1,123,864)	($1,110,833)	($1,097,801)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$156	$1,087	$1,285	$116,529	$263,393	$276,713	
5. Net Investment (Lines 2 - 3 + 4)	$3,167,876	$3,143,142	$3,118,409	$3,093,675	$3,068,942	$3,044,208	$3,019,475	$2,994,897	$2,971,095	$2,946,559	$3,037,070	$3,159,201	$3,147,787	
6. Average Net Investment		$3,155,509	$3,130,775	$3,106,042	$3,081,308	$3,056,575	$3,031,841	$3,007,186	$2,982,996	$2,958,827	$2,991,815	$3,098,135	$3,153,494	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$16,429	$16,300	$16,171	$16,043	$15,914	$15,785	$16,669	$16,535	$16,401	$16,584	$17,173	$17,480	$197,483
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3,497	$3,469	$3,442	$3,414	$3,387	$3,360	$3,385	$3,358	$3,330	$3,368	$3,487	$3,550	$41,046
8. Investment Expenses														
a. Depreciation (e)		$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$140,423
b. Amortization (f)		$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$156,378
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$44,659	$44,503	$44,347	$44,190	$44,034	$43,878	$44,787	$44,626	$44,465	$44,685	$45,394	$45,763	$535,331

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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23 - SPCC - Spill Prevention, Control & Countermeasures														
Transmission														
1. Investments														
a. Expenditures/Additions		$16,482	$5,272	$1,895	$1,721	$188,742	($2,698,829)	$0	$0	$0	$0	$0	$0	($2,484,717)
b. Clearings to Plant		$0	$0	$0	$0	$0	$2,699,258	$284	$6,747	$1,776	$165	$262	$16,713	$2,725,206
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,393,224	$1,393,224	$1,393,224	$1,393,224	$1,393,224	$1,393,224	$4,092,482	$4,092,766	$4,099,512	$4,101,289	$4,101,454	$4,101,716	$4,118,429	
3a. Less: Accumulated Depreciation	$391,083	$393,116	$395,149	$397,183	$399,216	$401,250	$405,578	$412,200	$418,829	$425,464	$432,101	$438,739	$445,391	
4. CWIP Non-Interest Bearing	$2,484,717	$2,501,199	$2,506,471	$2,508,366	$2,510,087	$2,698,829	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,486,858	$3,501,306	$3,504,545	$3,504,407	$3,504,095	$3,690,803	$3,686,904	$3,680,566	$3,680,684	$3,675,824	$3,669,352	$3,662,977	$3,673,038	
6. Average Net Investment		$3,494,082	$3,502,926	$3,504,476	$3,504,251	$3,597,449	$3,688,853	$3,683,735	$3,680,625	$3,678,254	$3,672,588	$3,666,165	$3,668,007	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$18,192	$18,238	$18,246	$18,245	$18,730	$19,206	$20,419	$20,402	$20,389	$20,357	$20,322	$20,332	$233,076
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3,872	$3,882	$3,883	$3,883	$3,986	$4,088	$4,146	$4,143	$4,140	$4,134	$4,127	$4,129	$48,412
8. Investment Expenses														
a. Depreciation (e)		$2,033	$2,033	$2,033	$2,033	$2,033	$4,328	$6,622	$6,628	$6,636	$6,637	$6,638	$6,652	$54,309
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$24,097	$24,153	$24,162	$24,161	$24,750	$27,621	$31,188	$31,173	$31,165	$31,129	$31,086	$31,113	$335,797

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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24 - Manatee Reburn														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$5,796	$10,214	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,010
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$31,847,709	$31,853,505	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	
3a. Less: Accumulated Depreciation	$11,424,851	$11,552,496	$11,680,173	$11,807,869	$11,935,565	$12,063,261	$12,190,958	$12,318,654	$12,446,350	$12,574,046	$12,701,742	$12,829,439	$12,957,135	
4. CWIP Non-Interest Bearing	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$20,422,858	$20,301,008	$20,183,546	$20,055,850	$19,928,153	$19,800,457	$19,672,761	$19,545,065	$19,417,369	$19,289,672	$19,161,976	$19,034,280	$18,906,584	
6. Average Net Investment		$20,361,933	$20,242,277	$20,119,698	$19,992,002	$19,864,305	$19,736,609	$19,608,913	$19,481,217	$19,353,521	$19,225,824	$19,098,128	$18,970,432	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$106,012	$105,390	$104,751	$104,086	$103,422	$102,757	$108,693	$107,986	$107,278	$106,570	$105,862	$105,154	$1,267,961
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$22,563	$22,430	$22,295	$22,153	$22,012	$21,870	$22,072	$21,928	$21,784	$21,641	$21,497	$21,353	$263,598
8. Investment Expenses														
a. Depreciation (e)		$127,646	$127,676	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$1,532,284
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$256,221	$255,496	$254,742	$253,936	$253,129	$252,323	$258,461	$257,610	$256,758	$255,907	$255,055	$254,204	$3,063,843

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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26 - UST Remove/Replacement														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	
3a. Less: Accumulated Depreciation	$51,171	$51,316	$51,460	$51,604	$51,748	$51,893	$52,037	$52,181	$52,326	$52,470	$52,614	$52,759	$52,903	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$64,275	$64,131	$63,987	$63,843	$63,698	$63,554	$63,410	$63,265	$63,121	$62,977	$62,832	$62,688	$62,544	
6. Average Net Investment		$64,203	$64,059	$63,915	$63,770	$63,626	$63,482	$63,337	$63,193	$63,049	$62,905	$62,760	$62,616	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$334	$334	$333	$332	$331	$331	$351	$350	$349	$349	$348	$347	$4,089
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$71	$71	$71	$71	$71	$70	$71	$71	$71	$71	$71	$70	$850
8. Investment Expenses														
a. Depreciation (e)		$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,732
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$550	$549	$548	$547	$546	$545	$567	$566	$565	$564	$563	$562	$6,670

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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28 - CWA 316(b) Phase II Rule														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	
3a. Less: Accumulated Depreciation	$24,767	$26,496	$28,225	$29,954	$31,683	$33,412	$35,141	$36,870	$38,599	$40,328	$42,057	$43,786	$45,515	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$746,543	$744,814	$743,085	$741,356	$739,627	$737,898	$736,169	$734,440	$732,711	$730,982	$729,253	$727,524	$725,795	
6. Average Net Investment		$745,679	$743,950	$742,221	$740,492	$738,763	$737,034	$735,305	$733,576	$731,847	$730,118	$728,389	$726,660	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$3,882	$3,873	$3,864	$3,855	$3,846	$3,837	$4,076	$4,066	$4,057	$4,047	$4,038	$4,028	$47,470
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$826	$824	$822	$821	$819	$817	$828	$826	$824	$822	$820	$818	$9,866
8. Investment Expenses														
a. Depreciation (e)		$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$20,748
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$6,438	$6,427	$6,416	$6,405	$6,394	$6,383	$6,633	$6,621	$6,609	$6,598	$6,586	$6,575	$78,084

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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31 - Clean Air Interstate Rule (CAIR) Compliance														
Base														
1. Investments														
a. Expenditures/Additions		$0	$16,431	$10,364	$28,592	$23,373	$75,849	$60,323	$49,511	$23,324	$147,121	$23,814	($458,701)	$0
b. Clearings to Plant		$15,838	$0	$0	$0	$0	$0	($12,507)	$0	$0	$0	$0	$2,010,183	$2,013,514
c. Retirements		$0	$0	$0	$0	$0	$0	($12,507)	$0	$0	$0	$0	$0	($12,507)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$43,439,531	$43,439,531
2. Plant-In-Service/Depreciation Base (b)	$357,929,865	$357,945,703	$357,945,703	$357,945,703	$357,945,703	$357,945,703	$357,945,703	$357,933,196	$357,933,196	$357,933,196	$357,933,196	$357,933,196	$359,943,378	
3a. Less: Accumulated Depreciation	$68,217,484	$57,277,285	$58,070,404	$58,863,522	$59,656,641	$60,449,760	$61,242,879	$62,023,416	$62,816,386	$63,609,356	$64,402,326	$65,195,296	$65,990,209	
3b. Less: Capital Recovery Unamortized Balance	($55,172,833)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	
4. CWIP Non-Interest Bearing	$0	$0	$16,431	$26,795	$55,386	$78,759	$154,608	$214,931	$264,442	$287,766	$434,887	$458,701	$0	
5. Net Investment (Lines 2 - 3 + 4)	$344,885,214	$344,107,949	$343,331,260	$342,548,506	$341,783,979	$341,014,232	$340,296,962	$339,564,241	$338,820,783	$338,051,137	$337,405,288	$336,636,132	$337,392,700	
6. Average Net Investment		$344,496,581	$343,719,605	$342,939,883	$342,166,242	$341,399,105	$340,655,597	$339,930,602	$339,192,512	$338,435,960	$337,728,212	$337,020,710	$337,014,416	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,793,589	$1,789,544	$1,785,484	$1,781,456	$1,777,462	$1,773,591	$1,884,255	$1,880,164	$1,875,970	$1,872,047	$1,868,126	$1,868,091	$21,949,780
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$381,737	$380,876	$380,012	$379,154	$378,304	$377,480	$382,626	$381,795	$380,944	$380,147	$379,351	$379,343	$4,561,769
8. Investment Expenses														
a. Depreciation (e)		$793,103	$793,119	$793,119	$793,119	$793,119	$793,119	$793,044	$792,970	$792,970	$792,970	$792,970	$794,913	$9,518,535
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,968,429	$2,963,538	$2,958,615	$2,953,729	$2,948,885	$2,944,190	$3,059,926	$3,054,929	$3,049,884	$3,045,164	$3,040,446	$3,042,347	$36,030,083

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	
3a. Less: Accumulated Depreciation	$393	$395	$398	$401	$404	$407	$409	$412	$415	$418	$421	$423	$426	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$920	$917	$914	$912	$909	$906	$903	$900	$898	$895	$892	$889	$886	
6. Average Net Investment		$919	$916	$913	$910	$907	$905	$902	$899	$896	$893	$891	$888	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$58
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$12
8. Investment Expenses														
a. Depreciation (e)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$34
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$104

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	
3a. Less: Accumulated Depreciation	$179,131	$181,566	$184,002	$186,437	$188,873	$191,308	$193,744	$196,179	$198,614	$201,050	$203,485	$205,921	$208,356	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,099,199	$1,096,764	$1,094,328	$1,091,893	$1,089,457	$1,087,022	$1,084,586	$1,082,151	$1,079,716	$1,077,280	$1,074,845	$1,072,409	$1,069,974	
6. Average Net Investment		$1,097,981	$1,095,546	$1,093,110	$1,090,675	$1,088,240	$1,085,804	$1,083,369	$1,080,933	$1,078,498	$1,076,062	$1,073,627	$1,071,191	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5,717	$5,704	$5,691	$5,678	$5,666	$5,653	$6,005	$5,992	$5,978	$5,965	$5,951	$5,938	$69,938
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,217	$1,214	$1,211	$1,209	$1,206	$1,203	$1,219	$1,217	$1,214	$1,211	$1,208	$1,206	$14,535
8. Investment Expenses														
a. Depreciation (e)		$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$29,225
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$9,369	$9,353	$9,338	$9,323	$9,307	$9,292	$9,660	$9,644	$9,628	$9,611	$9,595	$9,579	$113,698

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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31 - Clean Air Interstate Rule (CAIR) Compliance														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	
3a. Less: Accumulated Depreciation	($26,256,279)	($26,043,514)	($25,830,748)	($25,617,983)	($25,405,218)	($25,192,453)	($24,979,687)	($24,766,922)	($24,554,157)	($24,341,392)	($24,128,627)	($23,915,861)	($23,703,096)	
3b. Less: Capital Recovery Unamortized Balance	($61,677)	($61,034)	($60,392)	($59,749)	($59,107)	($58,464)	($57,822)	($57,179)	($56,537)	($55,895)	($55,252)	($54,610)	($53,967)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$82,208,206	$81,994,798	$81,781,391	$81,567,983	$81,354,575	$81,141,168	$80,927,760	$80,714,352	$80,500,945	$80,287,537	$80,074,129	$79,860,722	$79,647,314	
6. Average Net Investment		$82,101,502	$81,888,095	$81,674,687	$81,461,279	$81,247,872	$81,034,464	$80,821,056	$80,607,648	$80,394,241	$80,180,833	$79,967,425	$79,754,018	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$427,454	$426,343	$425,232	$424,120	$423,009	$421,898	$447,996	$446,813	$445,630	$444,447	$443,264	$442,081	$5,218,287
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$90,977	$90,740	$90,504	$90,267	$90,031	$89,794	$90,972	$90,732	$90,492	$90,252	$90,011	$89,771	$1,084,543
8. Investment Expenses														
a. Depreciation (e)		$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$2,553,183
b. Amortization (f)		$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$7,710
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$731,838	$730,490	$729,143	$727,795	$726,448	$725,100	$752,376	$750,953	$749,529	$748,106	$746,683	$745,260	$8,863,722

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
33 - MATS Project														
Base														
1. Investments														
a. Expenditures/Additions		$0	$3,720	$2	$2,885	$2,403	$1,885	($7,171)	$2	$0	($0)	($1)	$67,031	$70,755
b. Clearings to Plant		($67,031)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($67,031)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$84,067	$84,067
2. Plant-In-Service/Depreciation Base (b)	$109,327,769	$109,260,738	$109,260,738	$109,260,738	$109,260,738	$109,260,738	$109,260,738	$109,260,738	$109,260,738	$109,260,738	$109,260,738	$109,260,738	$109,260,738	
3a. Less: Accumulated Depreciation	$24,619,089	$24,869,587	$25,124,101	$25,378,616	$25,633,130	$25,887,645	$26,142,159	$26,396,674	$26,651,188	$26,905,703	$27,160,217	$27,414,732	$27,669,247	
3b. Less: Capital Recovery Unamortized Balance	($88,162)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	
4. CWIP Non-Interest Bearing	$0	$0	$3,720	$3,722	$6,607	$9,009	$10,895	$3,723	$3,725	$3,725	$3,725	$3,724	$70,755	
5. Net Investment (Lines 2 - 3 + 4)	$84,796,842	$84,475,219	$84,224,424	$83,969,911	$83,718,281	$83,466,170	$83,213,541	$82,951,855	$82,697,342	$82,442,827	$82,188,312	$81,933,797	$81,746,314	
6. Average Net Investment		$84,636,030	$84,349,821	$84,097,167	$83,844,096	$83,592,226	$83,339,855	$83,082,698	$82,824,598	$82,570,085	$82,315,570	$82,061,055	$81,840,056	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$440,649	$439,159	$437,844	$436,526	$435,215	$433,901	$460,532	$459,102	$457,691	$456,280	$454,869	$453,644	$5,365,414
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$93,785	$93,468	$93,188	$92,908	$92,629	$92,349	$93,518	$93,227	$92,941	$92,654	$92,368	$92,119	$1,115,154
8. Investment Expenses														
a. Depreciation (e)		$254,592	$254,515	$254,515	$254,515	$254,515	$254,515	$254,515	$254,515	$254,515	$254,515	$254,515	$254,515	$3,054,253
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$789,027	$787,142	$785,547	$783,949	$782,358	$780,765	$808,565	$806,844	$805,146	$803,449	$801,752	$800,278	$9,534,820

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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34 - St Lucie Cooling Water System Inspection & Maintenance														
Base														
1. Investments														
a. Expenditures/Additions		$1,849	($1,846)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP Non-Interest Bearing	$4,449,844	$4,451,693	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	
5. Net Investment (Lines 2 - 3 + 4)	$4,449,844	$4,451,693	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	
6. Average Net Investment		$4,450,768	$4,450,769	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$23,173	$23,173	$23,168	$23,168	$23,168	$23,168	$24,666	$24,666	$24,666	$24,666	$24,666	$24,666	$287,010
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$4,932	$4,932	$4,931	$4,931	$4,931	$4,931	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$59,640
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$28,104	$28,104	$28,099	$28,099	$28,099	$28,099	$29,675	$29,675	$29,675	$29,675	$29,675	$29,675	$346,650

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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35 - Martin Plant Drinking Water System Compliance														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$134,173	$0	$0	$0	$0	$0	$0	$0	$134,173
c. Retirements		$0	$0	$0	$0	$134,173	$0	$0	$0	$0	$0	$0	$0	$134,173
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	
3a. Less: Accumulated Depreciation	($105,681)	($105,681)	($105,681)	($105,681)	($105,681)	$28,633	$28,915	$29,197	$29,478	$29,760	$30,042	$30,324	$30,605	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$105,681	$105,681	$105,681	$105,681	$105,681	$105,540	$105,258	$104,976	$104,695	$104,413	$104,131	$103,849	$103,568	
6. Average Net Investment		$105,681	$105,681	$105,681	$105,681	$105,610	$105,399	$105,117	$104,835	$104,554	$104,272	$103,990	$103,708	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$550	$550	$550	$550	$550	$549	$583	$581	$580	$578	$576	$575	$6,772
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$117	$117	$117	$117	$117	$117	$118	$118	$118	$117	$117	$117	$1,407
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$141	$282	$282	$282	$282	$282	$282	$282	$2,113
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$667	$667	$667	$667	$808	$947	$983	$981	$979	$977	$975	$973	$10,293

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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35 - Martin Plant Drinking Water System Compliance														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$101,218	$0	$0	$0	$0	$0	$0	$0	$101,218
c. Retirements		$0	$0	$0	$0	$101,218	$0	$0	$0	$0	$0	$0	$0	$101,218
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	
3a. Less: Accumulated Depreciation	($79,724)	($79,724)	($79,724)	($79,724)	($79,724)	$21,600	$21,813	$22,025	$22,238	$22,451	$22,663	$22,876	$23,088	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$79,724	$79,724	$79,724	$79,724	$79,724	$79,618	$79,405	$79,193	$78,980	$78,768	$78,555	$78,342	$78,130	
6. Average Net Investment		$79,724	$79,724	$79,724	$79,724	$79,671	$79,512	$79,299	$79,086	$78,874	$78,661	$78,449	$78,236	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$415	$415	$415	$415	$415	$414	$440	$438	$437	$436	$435	$434	$5,109
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$88	$88	$88	$88	$88	$88	$89	$89	$89	$89	$88	$88	$1,062
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$106	$213	$213	$213	$213	$213	$213	$213	$1,594
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$503	$503	$503	$503	$609	$715	$741	$740	$739	$737	$736	$734	$7,765

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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36 - Low-Level Radioactive Waste Storage														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	
3a. Less: Accumulated Depreciation	$2,023,042	$2,063,001	$2,102,960	$2,142,918	$2,182,877	$2,222,836	$2,262,795	$2,302,754	$2,342,712	$2,382,671	$2,422,630	$2,462,589	$2,502,548	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$15,433,762	$15,393,803	$15,353,844	$15,313,885	$15,273,926	$15,233,968	$15,194,009	$15,154,050	$15,114,091	$15,074,132	$15,034,174	$14,994,215	$14,954,256	
6. Average Net Investment		$15,413,782	$15,373,823	$15,333,865	$15,293,906	$15,253,947	$15,213,988	$15,174,029	$15,134,071	$15,094,112	$15,054,153	$15,014,194	$14,974,235	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$80,250	$80,042	$79,834	$79,626	$79,418	$79,210	$84,111	$83,889	$83,668	$83,446	$83,225	$83,003	$979,723
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$17,080	$17,036	$16,991	$16,947	$16,903	$16,859	$17,080	$17,035	$16,990	$16,945	$16,900	$16,855	$203,621
8. Investment Expenses														
a. Depreciation (e)		$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$479,506
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$137,289	$137,037	$136,785	$136,532	$136,280	$136,028	$141,149	$140,883	$140,616	$140,350	$140,083	$139,817	$1,662,849

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
37 - DeSoto Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$6,672	$0	$0	$0	$0	$0	($6,672)	$0	$0	$9	$0	$9
b. Clearings to Plant		$2,119	$64	$8,781	$0	$8,456	$0	$0	$0	$2,525	$0	$1,860	$9,407	$33,212
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$153,528,141	$153,530,261	$153,530,325	$153,539,105	$153,539,105	$153,547,561	$153,547,561	$153,547,561	$153,547,561	$153,550,086	$153,550,086	$153,551,947	$153,561,354	
3a. Less: Accumulated Depreciation	$46,736,095	$47,181,389	$47,626,713	$48,072,091	$48,517,521	$48,963,002	$49,408,532	$49,854,063	$50,299,594	$50,745,139	$51,190,700	$51,636,272	$52,081,935	
4. CWIP Non-Interest Bearing	$1	$1	$6,672	$6,672	$6,672	$6,672	$6,672	$6,672	$1	$1	$1	$10	$10	
5. Net Investment (Lines 2 - 3 + 4)	$106,792,047	$106,348,872	$105,910,284	$105,473,687	$105,028,257	$104,591,232	$104,145,701	$103,700,171	$103,247,968	$102,804,948	$102,359,387	$101,915,685	$101,479,428	
6. Average Net Investment		$106,570,460	$106,129,578	$105,691,985	$105,250,972	$104,809,744	$104,368,467	$103,922,936	$103,474,069	$103,026,458	$102,582,167	$102,137,536	$101,697,557	
a. Average ITC Balance		$30,455,577	$30,333,511	$30,211,445	$30,089,379	$29,967,313	$29,845,247	$29,723,181	$29,601,115	$29,479,049	$29,356,983	$29,234,917	$29,112,851	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$614,176	$611,643	$609,127	$606,593	$604,058	$601,522	$628,013	$625,311	$622,617	$619,941	$617,262	$614,610	$7,374,872
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$126,728	$126,205	$125,685	$125,162	$124,638	$124,115	$124,662	$124,125	$123,590	$123,058	$122,526	$121,999	$1,492,494
8. Investment Expenses														
a. Depreciation (e)		$433,107	$433,138	$433,191	$433,243	$433,293	$433,344	$433,344	$433,344	$433,359	$433,374	$433,385	$433,476	$5,199,597
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$146,244
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($1,924,740)
9. Total System Recoverable Costs (Lines 7 & 8)		$1,025,803	$1,022,777	$1,019,795	$1,016,790	$1,013,781	$1,010,773	$1,037,810	$1,034,572	$1,031,357	$1,028,164	$1,024,965	$1,021,878	$12,288,466

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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38 - Space Coast Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$98	$98
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	
3a. Less: Accumulated Depreciation	$20,657,548	$20,857,432	$21,057,316	$21,257,199	$21,457,083	$21,656,967	$21,856,851	$22,056,735	$22,256,618	$22,456,502	$22,656,386	$22,856,270	$23,056,153	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$98	
5. Net Investment (Lines 2 - 3 + 4)	$49,933,863	$49,733,979	$49,534,095	$49,334,212	$49,134,328	$48,934,444	$48,734,560	$48,534,677	$48,334,793	$48,134,909	$47,935,025	$47,735,142	$47,535,356	
6. Average Net Investment		$49,833,921	$49,634,037	$49,434,154	$49,234,270	$49,034,386	$48,834,502	$48,634,619	$48,434,735	$48,234,851	$48,034,967	$47,835,083	$47,635,249	
a. Average ITC Balance		$13,053,063	$13,001,874	$12,950,685	$12,899,496	$12,848,307	$12,797,118	$12,745,929	$12,694,740	$12,643,551	$12,592,362	$12,541,173	$12,489,984	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$284,883	$283,742	$282,602	$281,462	$280,321	$279,181	$291,867	$290,669	$289,472	$288,274	$287,077	$285,880	$3,425,430
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$58,923	$58,687	$58,451	$58,215	$57,979	$57,743	$58,039	$57,801	$57,563	$57,325	$57,086	$56,848	$694,659
8. Investment Expenses														
a. Depreciation (e)		$195,492	$195,492	$195,492	$195,492	$195,492	$195,492	$195,492	$195,492	$195,492	$195,492	$195,492	$195,492	$2,345,901
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$52,704
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($807,156)
9. Total System Recoverable Costs (Lines 7 & 8)		$476,426	$475,050	$473,673	$472,297	$470,921	$469,544	$482,527	$481,091	$479,655	$478,220	$476,784	$475,349	$5,711,538

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
39 - Martin Next Generation Solar Energy Center														
Intermediate														
1. Investments														
a. Expenditures/Additions		($1,009,640)	$153,564	$231,358	$199,739	$153,824	$180,038	$159,716	$156,102	$197,711	$321,611	($62,953)	$412,834	$1,093,905
b. Clearings to Plant		$170,482	($535)	$9,459	$0	$0	$5,237	($1,726)	$0	$191,652	($371,354)	$152,597	$132,929	$288,741
c. Retirements		($994,001)	$0	$0	$0	$0	$0	$0	$0	$0	($212,370)	($26,000)	$0	($1,232,371)
d. Other (a)		($10,073)	($12,564)	($17,369)	($14,685)	($11,773)	($13,397)	($8,564)	($7,134)	($4,661)	($14,199)	($1,403)	($16,607)	($132,430)
2. Plant-In-Service/Depreciation Base (b)	$425,895,334	$426,055,743	$426,042,644	$426,034,733	$426,020,048	$426,008,275	$426,000,115	$425,989,825	$425,982,691	$426,169,682	$425,784,130	$425,935,323	$426,051,646	
3a. Less: Accumulated Depreciation	$102,540,857	$102,612,109	$103,675,074	$104,733,291	$105,794,247	$106,858,116	$107,920,367	$108,987,456	$110,055,973	$111,127,192	$111,976,288	$113,024,287	$114,083,425	
4. CWIP Non-Interest Bearing	$1,204,765	$195,125	$348,689	$580,047	$779,787	$933,610	$1,113,648	$1,273,365	$1,429,467	$1,627,178	$1,948,790	$1,885,836	$2,298,671	
5. Net Investment (Lines 2 - 3 + 4)	$324,559,243	$323,638,760	$322,716,259	$321,881,490	$321,005,587	$320,083,769	$319,193,396	$318,275,734	$317,356,186	$316,669,669	$315,756,632	$314,796,873	$314,266,891	
6. Average Net Investment		$324,099,001	$323,177,509	$322,298,874	$321,443,539	$320,544,678	$319,638,582	$318,734,565	$317,815,960	$317,012,927	$316,213,150	$315,276,752	$314,531,882	
a. Average ITC Balance		$90,346,777	$90,002,979	$89,659,181	$89,315,383	$88,971,585	$88,627,787	$88,283,989	$87,940,191	$87,596,393	$87,252,595	$86,908,797	$86,564,999	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,863,385	$1,857,917	$1,852,673	$1,847,550	$1,842,200	$1,836,813	$1,921,101	$1,915,409	$1,910,356	$1,905,322	$1,899,530	$1,894,801	$22,547,057
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$384,756	$383,638	$382,567	$381,521	$380,428	$379,326	$381,598	$380,475	$379,482	$378,493	$377,350	$376,423	$4,566,058
8. Investment Expenses														
a. Depreciation (e)		$1,025,771	$1,025,975	$1,026,031	$1,026,087	$1,026,087	$1,026,093	$1,026,097	$1,026,095	$1,026,325	$1,026,110	$1,025,847	$1,026,190	$12,312,709
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$594,660
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($5,421,012)
9. Total System Recoverable Costs (Lines 7 & 8)		$2,871,716	$2,865,334	$2,859,074	$2,852,962	$2,846,519	$2,840,037	$2,926,601	$2,919,783	$2,913,968	$2,907,729	$2,900,532	$2,895,217	$34,599,472

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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41 - Manatee Temporary Heating System														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	
3a. Less: Accumulated Depreciation	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
6. Average Net Investment		$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,186	$1,186	$1,186	$1,186	$1,186	$1,186	$1,262	$1,262	$1,262	$1,262	$1,262	$1,262	$14,686
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$252	$252	$252	$252	$252	$252	$256	$256	$256	$256	$256	$256	$3,052
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$1,438	$1,438	$1,438	$1,438	$1,438	$1,438	$1,518	$1,518	$1,518	$1,518	$1,518	$1,518	$17,738

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
41 - Manatee Temporary Heating System														
Intermediate														
1. Investments														
a. Expenditures/Additions		$745,746	($4,670,347)	$175,372	$29,114	$32,331	$722	$0	$0	$88,120	$75,600	$67	($7,794,300)	($11,317,575)
b. Clearings to Plant		$0	$5,241,976	$34,230	$179,789	$16,419	$21,547	$14,285	$5,681	$9,483	$46,388	$867	$3,483,508	$9,054,174
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,042,459	$4,042,459	$9,284,435	$9,318,665	$9,498,454	$9,514,874	$9,536,421	$9,550,706	$9,556,387	$9,565,870	$9,612,258	$9,613,125	$13,096,633	
3a. Less: Accumulated Depreciation	$4,041,596	$4,041,596	$4,049,153	$4,064,317	$4,079,789	$4,079,789	$4,111,354	$4,127,215	$4,143,106	$4,159,018	$4,175,011	$4,191,071	$4,246,609	
4. CWIP Non-Interest Bearing	$11,317,575	$12,063,322	$7,392,974	$7,568,346	$7,597,460	$7,629,792	$7,630,513	$7,630,513	$7,630,513	$7,718,633	$7,794,233	$7,794,300	$0	
5. Net Investment (Lines 2 - 3 + 4)	$11,318,439	$12,064,185	$12,628,256	$12,822,695	$13,016,125	$13,064,876	$13,055,580	$13,054,004	$13,043,795	$13,125,485	$13,231,480	$13,216,353	$8,850,024	
6. Average Net Investment		$11,691,312	$12,346,220	$12,725,475	$12,919,410	$13,040,501	$13,060,228	$13,054,792	$13,048,899	$13,084,640	$13,178,482	$13,223,917	$11,033,188	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$60,870	$64,279	$66,254	$67,264	$67,894	$67,997	$72,363	$72,331	$72,529	$73,049	$73,301	$61,158	$819,289
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$12,955	$13,681	$14,101	$14,316	$14,450	$14,472	$14,694	$14,688	$14,728	$14,834	$14,885	$12,419	$170,223
8. Investment Expenses														
a. Depreciation (e)		$0	$7,557	$15,164	$15,472	$0	$31,565	$15,862	$15,890	$15,912	$15,993	$16,061	$55,538	$205,013
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$73,825	$85,517	$95,519	$97,052	$82,344	$114,034	$102,919	$102,909	$103,169	$103,876	$104,247	$129,114	$1,194,525

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
41 - Manatee Temporary Heating System														
Peaking														
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,419,469	$4,419,469
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)													$4,419,469	
3a. Less: Accumulated Depreciation													$50,221	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)													$4,369,248	
6. Average Net Investment													$2,184,624	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,110	$12,110
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,459	$2,459
8. Investment Expenses														
a. Depreciation (e)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,221	$50,221
b. Amortization (f)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$64,790	$64,790

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
42 - Turkey Point Cooling Canal Monitoring Plan														
Base														
1. Investments														
a. Expenditures/Additions		$378,444	$1,269,634	$235,537	$733,376	$876,203	$1,288,441	$1,066,557	$465,312	$59,408	$675,161	$85,158	$2,069,273	$9,202,504
b. Clearings to Plant		$0	$50	$109,369	$0	$0	$0	$0	$0	$0	$0	$0	$0	$109,419
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$39,987,546	$39,987,546	$39,987,596	$40,096,965	$40,096,965	$40,096,965	$40,096,965	$40,096,965	$40,096,965	$40,096,965	$40,096,965	$40,096,965	$40,096,965	
3a. Less: Accumulated Depreciation	$2,066,377	$2,170,678	$2,274,979	$2,379,464	$2,484,132	$2,588,800	$2,693,468	$2,798,136	$2,902,804	$3,007,472	$3,112,140	$3,216,808	$3,321,476	
4. CWIP Non-Interest Bearing	$6,965,501	$7,343,945	$8,613,579	$8,849,115	$9,582,492	$10,458,695	$11,747,136	$12,813,693	$13,279,005	$13,338,412	$14,013,573	$14,098,732	$16,168,005	
5. Net Investment (Lines 2 - 3 + 4)	$44,886,669	$45,160,812	$46,326,195	$46,566,617	$47,195,325	$47,966,860	$49,150,633	$50,112,522	$50,473,166	$50,427,906	$50,998,399	$50,978,889	$52,943,494	
6. Average Net Investment		$45,023,741	$45,743,504	$46,446,406	$46,880,971	$47,581,093	$48,558,747	$49,631,578	$50,292,844	$50,450,536	$50,713,152	$50,988,644	$51,961,191	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$234,412	$238,159	$241,819	$244,081	$247,726	$252,817	$275,111	$278,776	$279,650	$281,106	$282,633	$288,024	$3,144,314
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$49,891	$50,688	$51,467	$51,949	$52,725	$53,808	$55,865	$56,610	$56,787	$57,083	$57,393	$58,488	$652,753
8. Investment Expenses														
a. Depreciation (e)		$104,301	$104,301	$104,485	$104,668	$104,668	$104,668	$104,668	$104,668	$104,668	$104,668	$104,668	$104,668	$1,255,099
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$388,604	$393,149	$397,771	$400,698	$405,119	$411,293	$435,644	$440,054	$441,105	$442,857	$444,694	$451,180	$5,052,166

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8A

JANUARY 2019 THROUGH DECEMBER 2019

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
44 - Martin Plant Barley Barber Swamp Iron Mitigation														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	
3a. Less: Accumulated Depreciation	$15,627	$15,824	$16,022	$16,219	$16,416	$16,613	$16,810	$17,007	$17,205	$17,402	$17,599	$17,796	$17,993	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$78,262	$78,065	$77,868	$77,671	$77,474	$77,276	$77,079	$76,882	$76,685	$76,488	$76,291	$76,093	$75,896	
6. Average Net Investment		$78,164	$77,967	$77,769	$77,572	$77,375	$77,178	$76,981	$76,784	$76,586	$76,389	$76,192	$75,995	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$407	$406	$405	$404	$403	$402	$427	$426	$425	$423	$422	$421	$4,970
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$87	$86	$86	$86	$86	$86	$87	$86	$86	$86	$86	$86	$1,033
8. Investment Expenses														
a. Depreciation (e)		$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$2,366
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$691	$689	$688	$687	$686	$685	$711	$709	$708	$707	$705	$704	$8,369

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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44 - Martin Plant Barley Barber Swamp Iron Mitigation														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	
3a. Less: Accumulated Depreciation	$11,789	$11,938	$12,086	$12,235	$12,384	$12,533	$12,681	$12,830	$12,979	$13,128	$13,276	$13,425	$13,574	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$59,040	$58,891	$58,743	$58,594	$58,445	$58,296	$58,148	$57,999	$57,850	$57,701	$57,553	$57,404	$57,255	
6. Average Net Investment		$58,966	$58,817	$58,668	$58,519	$58,371	$58,222	$58,073	$57,924	$57,776	$57,627	$57,478	$57,329	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$307	$306	$305	$305	$304	$303	$322	$321	$320	$319	$319	$318	$3,749
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$65	$779
8. Investment Expenses														
a. Depreciation (e)		$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$1,785
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$521	$520	$519	$518	$517	$516	$536	$535	$534	$533	$532	$531	$6,314

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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45 - 800 MW Unit ESP														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	
3a. Less: Accumulated Depreciation	$11,624	$12,029	$12,433	$12,838	$13,243	$13,648	$14,053	$14,458	$14,863	$15,267	$15,672	$16,077	$16,482	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$52,135	$51,730	$51,325	$50,920	$50,515	$50,111	$49,706	$49,301	$48,896	$48,491	$48,086	$47,681	$47,276	
6. Average Net Investment		$51,932	$51,528	$51,123	$50,718	$50,313	$49,908	$49,503	$49,098	$48,693	$48,289	$47,884	$47,479	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$270	$268	$266	$264	$262	$260	$274	$272	$270	$268	$265	$263	$3,203
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$58	$57	$57	$56	$56	$55	$56	$55	$55	$54	$54	$53	$666
8. Investment Expenses														
a. Depreciation (e)		$405	$405	$405	$405	$405	$405	$405	$405	$405	$405	$405	$405	$4,858
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$733	$730	$728	$725	$723	$720	$735	$732	$730	$727	$724	$721	$8,728

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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45 - 800 MW Unit ESP														
Peaking														
1. Investments														
a. Expenditures/Additions		$5,349	$0	$0	$49	($82,658)	$0	$0	$0	$0	$0	$0	$0	($77,259)
b. Clearings to Plant		($9,295)	$0	$0	$0	$89,585	$13,558	$0	$0	$0	$0	$0	$0	$93,848
c. Retirements		($9,295)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9,295)
d. Other (a)		($159)	$0	$0	($1)	($205)	($362)	$0	$0	$0	$0	$0	$0	($727)
2. Plant-In-Service/Depreciation Base (b)	$107,870,694	$107,861,240	$107,861,240	$107,861,240	$107,861,238	$107,950,618	$107,963,814	$107,963,814	$107,963,814	$107,963,814	$107,963,814	$107,963,814	$107,963,814	
3a. Less: Accumulated Depreciation	($70,770,312)	($70,350,563)	($69,921,379)	($69,492,194)	($69,063,010)	($68,633,851)	($68,204,644)	($67,775,048)	($67,345,451)	($66,915,854)	($66,486,258)	($66,056,661)	($65,627,065)	
4. CWIP Non-Interest Bearing	$76,881	$82,231	$82,231	$82,231	$82,280	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	
5. Net Investment (Lines 2 - 3 + 4)	$178,717,887	$178,294,034	$177,864,849	$177,435,664	$177,006,528	$176,584,091	$176,168,080	$175,738,483	$175,308,887	$174,879,290	$174,449,694	$174,020,097	$173,590,500	
6. Average Net Investment		$178,505,960	$178,079,441	$177,650,256	$177,221,096	$176,795,310	$176,376,085	$175,953,281	$175,523,685	$175,094,088	$174,664,492	$174,234,895	$173,805,299	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$929,374	$927,154	$924,919	$922,685	$920,468	$918,285	$975,319	$972,938	$970,557	$968,176	$965,794	$963,413	$11,359,083
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$197,802	$197,330	$196,854	$196,379	$195,907	$195,442	$198,053	$197,569	$197,086	$196,602	$196,119	$195,635	$2,360,779
8. Investment Expenses														
a. Depreciation (e)		$429,203	$429,185	$429,185	$429,185	$429,364	$429,569	$429,597	$429,597	$429,597	$429,597	$429,597	$429,597	$5,153,270
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$1,556,380	$1,553,668	$1,550,958	$1,548,248	$1,545,739	$1,543,297	$1,602,969	$1,600,104	$1,597,239	$1,594,374	$1,591,510	$1,588,645	$18,873,132

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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50 - Steam Electric Effluent Guidelines Revised Rules														
Base														
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$0	$0	$11,921	$16,604	$186,085	$172,364	$110,516	$485,639	$983,131
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3a. 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	$11,921	$28,525	$214,611	$386,975	$497,491	$983,131	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	$11,921	$28,525	$214,611	$386,975	$497,491	$983,131	
6. Average Net Investment		$0	$0	$0	$0	$0	$0	$5,961	$20,223	$121,568	$300,793	$442,233	$740,311	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$0	$0	$0	$0	$0	$33	$112	$674	$1,667	$2,451	$4,104	$9,041
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$0	$0	$0	$0	$0	$0	$7	$23	$137	$339	$498	$833	$1,836
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$40	$135	$811	$2,006	$2,949	$4,937	$10,877

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8A

JANUARY 2019 THROUGH DECEMBER 2019

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
54 - Coal Combustion Residuals														
Base														
1. Investments														
a. Expenditures/Additions		($1,595,767)	$1,507,046	$1,420,380	$3,300,996	$2,278,422	$2,562,423	$1,507,049	$2,226,792	$2,102,604	$2,324,075	$2,155,953	$13,230,760	$33,020,735
b. Clearings to Plant		$50,776,893	$0	$0	$0	($4,247,895)	$0	$9,413	$0	($339,020)	$5,416	($5,416)	$0	$46,199,391
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$524,089	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$524,089
2. Plant-In-Service/Depreciation Base (b)	$199,237	$51,500,219	$51,500,219	$51,500,219	$51,500,219	$47,252,325	$47,252,325	$47,261,738	$47,261,738	$46,922,718	$46,928,133	$46,922,718	$46,922,718	
3a. Less: Accumulated Depreciation	$7,167	$646,772	$765,079	$883,386	$1,001,693	$1,115,062	$1,223,492	$1,331,929	$1,440,372	$1,548,420	$1,656,078	$1,763,735	$1,871,389	
3b. Less: Capital Recovery Unamortized Balance	($56,167)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	
4. CWIP Non-Interest Bearing	$20,605,956	$19,010,190	$20,517,236	$21,937,616	$25,238,612	$27,517,034	$30,079,458	$31,586,507	$33,813,299	$35,915,903	$38,239,978	$40,395,931	$53,626,692	
5. Net Investment (Lines 2 - 3 + 4)	$20,854,193	$69,918,887	$71,307,627	$72,609,700	$75,792,389	$73,709,548	$76,163,540	$77,571,566	$79,689,915	$81,345,451	$83,567,284	$85,610,164	$98,733,270	
6. Average Net Investment		$45,386,540	$70,613,257	$71,958,663	$74,201,044	$74,750,968	$74,936,544	$76,867,553	$78,630,741	$80,517,683	$82,456,367	$84,588,724	$92,171,717	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$236,301	$367,641	$374,646	$386,321	$389,184	$390,150	$426,081	$435,855	$446,314	$457,061	$468,880	$510,913	$4,889,347
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$50,293	$78,247	$79,737	$82,222	$82,832	$83,037	$86,522	$88,507	$90,631	$92,813	$95,213	$103,748	$1,013,802
8. Investment Expenses														
a. Depreciation (e)		$116,433	$118,307	$118,307	$118,307	$113,369	$108,431	$108,437	$108,442	$108,048	$107,658	$107,658	$107,654	$1,341,050
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$403,026	$564,195	$572,690	$586,850	$585,384	$581,618	$621,040	$632,804	$644,993	$657,531	$671,751	$722,316	$7,244,199

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8A, pages 66-69.
(c) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8A, pages 66-69.
(f) Applicable amortization period(s). See Form 42-8A, pages 66-69.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2019 period of 6.480% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period of 6.604% based on the May 2019 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2019 period of 1.670% based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period of 1.661% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8A

JANUARY 2019 THROUGH DECEMBER 2019

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1 Working Capital Dr (Cr)														
a. 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
b. 158.200 Allowances Withheld	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 182.300 Other Regulatory Assets-Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
d 254.900Other Regulatory Liabilities-Gains	($546)	($523)	($500)	($477)	($454)	($564)	($506)	($462)	($418)	($374)	($330)	($286)	($242)	
2 Total Working Capital	($546)	($523)	($500)	($477)	($454)	($564)	($506)	($462)	($418)	($374)	($330)	($286)	($242)	
3 Average Net Working Capital Balance		($534)	($511)	($488)	($465)	($509)	($535)	($484)	($440)	($396)	($352)	($308)	($264)	
4 Return on Average Net Working Capital Balance														
a. Equity Component grossed up for taxes	($3)	($3)	($3)	($3)	($2)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($1)	
b. Debt Component	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($0)	($0)	($0)	($0)	
5. Total Return Component	($4)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($2)	($34)
6. Expense Dr (Cr)														
a. 411.800 Gains from Dispositions of Allowances	($31)	($23)	($23)	($23)	($23)	($25)	($44)	($44)	($44)	($44)	($44)	($44)	($44)	
b. 411.900 Losses from Dispositions of Allowances	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 509.000 Allowance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Net Expense (Lines 6a+6b+6c)	($31)	($23)	($23)	($23)	($23)	($25)	($44)	($44)	($44)	($44)	($44)	($44)	($44)	($425)
8. Total Recoverable Costs (Lines 5+6)	($35)	($26)	($26)	($26)	($26)	($28)	($47)	($47)	($47)	($47)	($46)	($46)	($46)	($459)

(a) The Gross-up factor for taxes is 1/0.74655, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2019 period is 4.7156%, based on May 2018 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2019 period is 5.0206% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity.

(b) The Debt Component for the Jan. – Jun. 2019 period is 1.3297% is based on the May 2018 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2019 period is 1.3507% based on the May 2019 Earning Surveillance Report.

(c) Line 8a times Line 9

(d) Line 8b times Line 10

(e) Line 5 is reported on Capital Schedule

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

Florida Power & Light Company
Environmental Cost Recovery Clause
2019 Annual Capital Depreciation Schedule

Project	Function	Unit	Utility	DEPR RATE	12/1/2018	12/1/2019
002-LOW NOX BURNER TECHNOLOGY	02 - Steam Generation Plant	Turkey Pt U1	31200	0.000%	0	0
002-LOW NOX BURNER TECHNOLOGY Total					**0**	**0**
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee Comm	31200	7.620%	65,605	65,605
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31100	1.740%	56,430	56,430
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31200	4.640%	424,505	424,505
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31100	1.830%	56,333	56,333
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31200	4.990%	468,728	468,728
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31200	4.450%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31650	5-Year	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31670	7-Year	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31100	2.680%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31200	4.530%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31100	2.390%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31200	4.640%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Scherer U4	31200	2.790%	515,653	515,653
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP - Comm	31100	1.090%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP U1	31200	2.120%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP U2	31200	2.350%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.000%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31200	0.000%	-	
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt U1	31200	0.000%	-	
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34100	2.200%	-	
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34500	1.600%	-	
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale GTs	34300	8.250%	10,225	10,225
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U4	34300	4.110%	-	
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U5	34300	5.000%	-	
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U2	34300	3.460%	365,000	365,000
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3 SC Peaker	34100	3.380%	6,098	6,098
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3 SC Peaker	34300	4.540%	141,021	141,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Manatee U3	34300	3.350%	87,691	87,691
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U3	34300	4.490%	627,875	615,469
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U4	34300	3.920%	620,088	598,036
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U8	34300	3.370%	13,693	13,693
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U4	34300	4.000%	310,021	310,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U5	34300	4.120%	273,035	273,035
003-CONTINUOUS EMISSION MONITORING Total					**4,042,003**	**4,007,544**
004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.000%		
004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION Total						
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31100	3.170%	3,111,263	3,111,263
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31200	7.620%	174,543	174,543
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U1	31200	4.640%	104,845	104,845
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U2	31200	4.990%	127,429	127,429
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31100	2.520%	198,665	198,665
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31200	4.450%	-	
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U1	31100	2.680%	-	
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U2	31100	2.390%	-	
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31100	1.090%	-	
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31200	1.440%	-	
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.000%	-	
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale Comm	34200	3.090%	898,111	898,111
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale GTs	34200	4.730%	584,290	584,290
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers GTs	34200	7.840%	133,479	133,479
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers U3 SC Peaker	34200	3.580%	18,616	18,616
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Martin Comm	34200	2.420%	455,941	455,941
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	PtEverglades GTs	34200	0.000%	-	
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	08 - General Plant	General Plant	39000	1.500%	5,837,840	5,837,840
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total					**11,645,022**	**11,645,022**
007-RELOCATE TURBINE LUBE OIL PIPING	03 - Nuclear Generation Plant	StLucie U1	32300	5.110%	31,030	31,030
007-RELOCATE TURBINE LUBE OIL PIPING Total					**31,030**	**31,030**
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.170%	46,882	46,882
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31670	7-Year	21,347	
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31600	3.790%	-	
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31650	5-Year	116,547	227,249
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31670	7-Year	298,813	298,813
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.000%	-	

Project	Function	Unit	Utility	DEPR RATE	12/1/2018	12/1/2019
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31670	7-Year		
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtLauderdale Comm	34100	2.200%	358,636	358,636
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtMyers Comm	34650	5-Year	-	
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	PtEverglades U5	34100	2.640%		22,550
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Sanford Comm	34100	2.400%	15,922	15,922
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.000%	2,995	2,995
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39000	1.500%	4,413	4,413
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39190	3-Year	-	
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total					**865,555**	**977,460**
010-REROUTE STORMWATER RUNOFF	03 - Nuclear Generation Plant	StLucie Comm	32100	2.250%	117,794	117,794
010-REROUTE STORMWATER RUNOFF Total					**117,794**	**117,794**
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31100	1.510%	524,873	524,873
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31200	2.230%	328,762	328,762
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31400	2.080%	689	689
012-SCHERER DISCHARGE PIPELINE Total					**854,324**	**854,324**
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U1	31200	4.530%	-	
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U2	31200	4.640%	-	
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total					-	
021-ST.LUCIE TURTLE NETS	03 - Nuclear Generation Plant	StLucie Comm	32100	2.250%	6,909,559	6,909,559
021-ST.LUCIE TURTLE NETS Total					**6,909,559**	**6,909,559**
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.170%	601,217	601,217
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Martin Comm	31100	2.520%	2,271,574	2,271,574
022-PIPELINE INTEGRITY MANAGEMENT Total					**2,872,791**	**2,872,791**
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31100	3.170%	1,243,306	1,243,306
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31200	7.620%	33,272	33,272
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31500	2.340%	26,325	26,325
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U1	31200	4.640%	45,750	45,750
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U2	31200	4.990%	37,431	37,431
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31100	2.520%	37,158	37,158
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31500	3.570%	-	
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.000%	-	
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32300	5.110%	712,225	712,225
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32400	3.200%	745,335	745,335
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U2	32300	3.860%	552,390	552,390
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.130%	990,124	990,124
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32570	7-Year	245,362	245,362
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34100	2.200%	189,219	189,219
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34200	3.090%	1,480,169	1,480,169
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34300	5.200%	28,250	28,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34100	4.180%	-	
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34200	4.730%	513,250	513,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34100	7.400%	98,715	98,715
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34200	7.840%	629,983	629,983
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34500	7.770%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U2	34300	3.460%	49,727	49,727
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U3 SC Peaker	34500	3.400%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin Comm	34100	2.240%	523,498	523,498
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin U8	34200	2.700%	84,868	84,868
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades Comm	34200	2.900%	2,728,283	2,728,283
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34100	0.000%	-	
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34200	0.000%	-	
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34500	0.000%	-	
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Sanford Comm	34100	2.400%	288,383	288,383
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Radial	35200	1.700%	6,946	6,946
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.700%	1,142,640	1,142,640
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.040%	177,982	2,903,187
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35800	1.870%	65,655	65,655
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.750%	3,303,417	3,336,463
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.000%	70,499	70,499
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	08 - General Plant	General Plant	39000	1.500%	146,691	146,691
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total					**16,221,715**	**18,979,966**
024-GAS REBURN	02 - Steam Generation Plant	Manatee U1	31200	4.640%	16,454,014	16,470,024
024-GAS REBURN	02 - Steam Generation Plant	Manatee U2	31200	4.990%	15,393,694	15,393,694
024-GAS REBURN Total					**31,847,709**	**31,863,719**
026-UST REPLACEMENT/REMOVAL	08 - General Plant	General Plant	39000	1.500%	115,447	115,447
026-UST REPLACEMENT/REMOVAL Total					**115,447**	**115,447**
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	CapeCana Comm CC	34100	2.690%	771,310	771,310
028-CWA 316B PHASE II RULE Total					**771,310**	**771,310**
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee Comm	31100	3.170%	102,052	102,052

Project	Function	Unit	Utility	DEPR RATE	12/1/2018	12/1/2019
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31200	4.640%	20,059,060	20,059,060
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31400	4.030%	7,240,124	7,240,124
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31200	4.990%	20,457,354	20,457,354
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31400	3.720%	7,905,907	7,905,907
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31200	4.450%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31400	3.480%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31200	4.530%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31400	3.350%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31200	4.640%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31400	4.790%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.320%	1,153,382	3,179,403
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31100	2.300%	82,366,984	82,366,984
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31200	2.790%	254,475,936	254,475,936
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31400	1.890%	(94,224)	(94,224)
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31500	2.490%	19,615,426	19,615,426
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31600	1.880%	399,586	399,586
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31670	7-Year	12,775	268
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U1	31200	2.120%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U1	31500	1.460%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U1	31600	1.140%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U2	31200	2.350%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U2	31500	1.840%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U2	31600	1.580%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtLauderdale GTs	34300	8.250%	110,242	110,242
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtMyers GTs	34300	8.220%	57,855	57,855
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34100	2.240%	699,143	699,143
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34300	2.560%	244,343	244,343
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34500	2.040%	292,499	292,499
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	PtEverglades GTs	34300	0.000%	-	
031-CLEAN AIR INTERSTATE RULE-CAIR	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	2.570%	1,313	1,313
031-CLEAN AIR INTERSTATE RULE-CAIR Total					**415,099,758**	**417,113,272**
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.320%	(1,234,037)	(1,234,037)
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31200	2.790%	110,561,806	110,494,775
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	SJRPP U1	31200	2.120%	-	
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	SJRPP U2	31200	2.350%	-	
033-CLEAN AIR MERCURY RULE-CAMR Total					**109,327,769**	**109,260,738**
035-MARTIN PLANT DRINKING WATER COMP	02 - Steam Generation Plant	Martin Comm	31100	2.520%	-	235,391
035-MARTIN PLANT DRINKING WATER COMP Total					**-**	**235,391**
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	StLucie Comm	32100	2.250%	7,601,405	7,601,405
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.130%	9,855,399	9,855,399
036-LOW LEV RADI WSTE-LLW Total					**17,456,804**	**17,456,804**
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34000	0.000%	255,507	255,507
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34100	3.490%	5,263,916	5,263,916
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34300	3.360%	115,292,583	115,292,583
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34500	3.650%	26,746,246	26,746,246
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34630	3-Year	10,487	15,749
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34650	5-Year	51,031	51,031
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34670	7-Year	154,915	182,866
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	TransGeneratorLead	35300	2.040%	308,244	308,244
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.700%	7,427	7,427
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.040%	695,782	695,782
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.640%	1,695,869	1,695,869
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.320%	394,418	394,418
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.380%	191,358	191,358
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.750%	540,994	540,994
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.900%	1,890,938	1,890,938
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39220	10.000%	28,426	28,426
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year	-	
037-DE SOTO SOLAR PROJECT Total					**153,528,141**	**153,561,354**
038-SPACE COAST SOLAR PROJECT	01 - Intangible Plant	Intangible Plant	30300	various	6,359,027	6,359,027
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34100	3.450%	3,893,263	3,893,263
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34300	3.300%	51,550,587	51,550,587
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34500	3.510%	6,126,699	6,126,699
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34630	3-Year	-	
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34650	5-Year	35,202	35,202
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34670	7-Year	-	
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	TransGeneratorLead	35300	2.040%	789,138	789,138
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.040%	139,391	139,391
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.640%	1,328,699	1,328,699

Project	Function	Unit	Utility	DEPR RATE	12/1/2018	12/1/2019
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.750%	274,858	274,858
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.900%	62,689	62,689
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39220	10.000%	31,858	31,858
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year	-	
038-SPACE COAST SOLAR PROJECT Total					**70,591,411**	**70,591,411**
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34000	0.000%	216,844	216,844
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34100	2.990%	20,756,023	20,756,023
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34300	2.880%	398,581,449	398,862,026
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34500	2.990%	4,122,852	4,122,852
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34600	2.850%	57,742	56,448
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34650	5-Year	-	
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34670	7-Year	129,522	138,981
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin U8	34300	3.370%	423,126	423,126
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.320%	603,692	603,692
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.380%	364,159	364,159
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36400	0.000%		
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	1.420%	94,476	94,476
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	1.960%	2,728	2,728
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39220	10.000%	121,101	121,101
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39240	2.630%	332,682	332,682
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39290	4.990%	88,938	88,938
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39420	7-Year	-	
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year	-	
039-MARTIN SOLAR PROJECT Total					**425,895,334**	**426,184,075**
041-PRV MANATEE HEATING SYSTEM	02 - Steam Generation Plant	PtEverglades Comm	31400	42 mos.	-	
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	CapeCanaveral Comm	34300	0.000%	4,042,459	4,042,459
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	FtLauderdale Comm	34300	44 mos.		7,891,910
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	FtMyers U2	34300	3.460%		5,581,733
041-PRV MANATEE HEATING SYSTEM	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	various	276,404	276,404
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	various	73,267	73,267
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	various	471,542	471,542
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36400	0.000%		
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36410	various	137,247	137,247
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36420	various	36,431	36,431
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	various	307,599	307,599
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	various	221,326	221,326
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	various	168,995	168,995
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36910	various	607	607
041-PRV MANATEE HEATING SYSTEM	08 - General Plant	General Plant	39720	7-Year		
041-PRV MANATEE HEATING SYSTEM Total					**5,735,878**	**19,209,521**
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.130%	39,987,546	39,915,222
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32500	3.670%		181,743
042-PTN COOLING CANAL MONITORING SYS Total					**39,987,546**	**40,096,965**
044-Barley Barber Swamp Iron Mitiga	02 - Steam Generation Plant	Martin Comm	31100	2.520%	164,719	164,719
044-Barley Barber Swamp Iron Mitiga Total					**164,719**	**164,719**
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee Comm	31200	7.620%	153,660	153,660
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31200	4.640%	44,854,496	44,854,496
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31500	4.110%	4,524,074	4,524,074
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31600	3.910%	1,021,918	1,021,918
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31200	4.990%	51,505,899	51,505,899
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31500	4.480%	4,793,798	4,793,798
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31600	4.790%	1,071,311	1,174,454
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31200	4.530%	-	
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31500	3.120%	-	
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31600	3.810%	-	
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31200	4.640%	9,295	
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31500	3.560%	-	
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31600	4.310%	-	
045-800 MW UNIT ESP PROJECT Total					**107,934,452**	**108,028,300**
054-Coal Combustion Residuals	02 - Steam Generation Plant	Scherer Comm	31100	1.510%	199,237	208,650
054-Coal Combustion Residuals	02 - Steam Generation Plant	Scherer U4	31200	2.790%		46,189,978
054-Coal Combustion Residuals	02 - Steam Generation Plant	SJRPP - Comm	31100	1.090%	-	
054-Coal Combustion Residuals Total					**199,237**	**46,398,629**
Grand Total					**1,422,215,307**	**1,481,088,114**

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

FORM 42-9A

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2018 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	9,493,721,402	27.894%	4.33%	1.21%	1.21%
SHORT_TERM_DEBT	1,266,291,093	3.721%	2.42%	0.09%	0.09%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	403,315,602	1.185%	2.08%	0.02%	0.02%
COMMON_EQUITY	15,115,086,261	44.410%	10.55%	4.69%	6.28%
DEFERRED_INCOME_TAX	7,597,792,885	22.323%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	159,231,867	0.468%	8.15%	0.04%	0.05%
TOTAL	$34,035,439,111	100.00%		6.05%	7.65%

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	$9,493,721,402	38.58%	4.328%	1.670%	1.670%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	15,115,086,261	61.42%	10.550%	6.480%	8.680%
TOTAL	$24,608,807,663	100.00%		8.150%	10.350%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.2073%
SHORT TERM DEBT	0.0900%
CUSTOMER DEPOSITS	0.0246%
TAX CREDITS -WEIGHTED	0.0078%
TOTAL DEBT	**1.3297%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.6852%
TAX CREDITS -WEIGHTED	0.0303%
TOTAL EQUITY	**4.7156%**
TOTAL	6.0452%
PRE-TAX EQUITY	6.3165%
PRE-TAX TOTAL	7.6461%

Note:

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

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

FORM 42-9A

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2019 EARNINGS SURVEILLANCE REPORT

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

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

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

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

Note:

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

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

FORM: 42-1E

JANUARY 2020 THROUGH DECEMBER 2020

	2020
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$4,556,972
2. Interest Provision (Form 42-2E, Line 6)	$206,813
3. Sum of Current Period Adjustments (Form 42-2E, Line 11)	$0
4. Actual/Estimated True-up to be refunded/(recovered)	$4,763,785

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 3
PARTY: RBD-2
DESCRIPTION: Environmental Cost Recovery Actual/ Estimated True-up January 2020 - December 2020 Commission Forms 4...

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

FORM: 42-2E

JANUARY 2020 THROUGH DECEMBER 2020

	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1. ECRC Revenues (net of Revenue Taxes)	$11,896,518	$10,915,932	$11,468,761	$13,476,593	$13,484,729	$14,902,988	$15,950,075	$15,957,383	$15,548,231	$14,537,700	$12,464,511	$11,932,704	$162,536,127
2. True-up Provision [b]	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$2,442,450	$29,309,402
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$14,338,969	$13,358,383	$13,911,211	$15,919,043	$15,927,179	$17,345,438	$18,392,525	$18,399,834	$17,990,681	$16,980,151	$14,906,961	$14,375,155	$191,845,529
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5E-2, Line 9)	$2,659,886	$3,252,499	$2,187,838	$2,533,824	$2,586,271	$2,342,763	$2,545,978	$2,436,751	$2,448,715	$2,928,823	$2,815,881	$10,706,032	$39,445,262
b. Capital Investment Projects (Form 42-7E-2, Line 8)	$12,370,558	$12,356,337	$12,349,948	$12,342,143	$12,341,323	$12,373,866	$12,310,497	$12,298,233	$12,288,999	$12,277,648	$12,259,508	$12,274,236	$147,843,295
c. Total Jurisdictional ECRC Costs	$15,030,444	$15,608,836	$14,537,786	$14,875,967	$14,927,593	$14,716,630	$14,856,475	$14,734,984	$14,737,714	$15,206,471	$15,075,388	$22,980,268	$187,288,557
5. Over/(Under) Recovery (Line 3 - Line 4c)	($691,475)	($2,250,453)	($626,575)	$1,043,076	$999,586	$2,628,809	$3,536,050	$3,664,849	$3,252,967	$1,773,679	($168,427)	($8,605,113)	$4,556,972
6. Interest Provision (Form 42-3E, Line 10)	$56,297	$50,632	$53,635	$30,233	$1,783	$1,996	$2,039	$2,117	$2,185	$2,189	$2,080	$1,625	$206,813
7. Prior Periods True-Up to be (Collected)/Refunded	$29,309,402	$26,232,352	$21,590,657	$18,575,843	$17,207,276	$15,766,195	$15,954,550	$17,050,189	$18,274,705	$19,087,406	$18,420,825	$15,812,028	$29,309,402
a. Deferred True-Up (Form 42-1A, Line 7) [c]	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	$14,087,943	
8. True-Up Collected /(Refunded) (See Line 2)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($2,442,450)	($29,309,402)
9. End of Period True-Up (Lines 5+6+7+7a+8)	$40,319,717	$35,678,024	$32,663,210	$31,294,645	$29,854,138	$30,042,493	$31,138,132	$32,362,648	$33,175,350	$32,508,767	$29,899,971	$18,854,033	$4,763,785
10. Adjustments to Period Total True-Up Including Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11. End of Period Total Net True-Up (Lines 9+10)	$40,319,717	$35,678,024	$32,663,210	$31,294,645	$29,854,138	$30,042,493	$31,138,132	$32,362,648	$33,175,350	$32,508,767	$29,899,971	$18,854,033	$4,763,785

[b] As approved in Order No. PSC-2019-0500-FOF-EI issued November 22, 2019.

[c] From FPL's 2020 Final True-up filed on April 1, 2020.

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

FORM: 42-3E

JANUARY 2020 THROUGH DECEMBER 2020

	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1. Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$43,397,345	$40,320,295	$35,678,600	$32,663,786	$31,295,219	$29,854,138	$30,042,493	$31,138,133	$32,362,648	$33,175,350	$32,508,768	$29,899,971	
2. Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	$40,263,420	$35,627,392	$32,609,575	$31,264,412	$29,852,355	$30,040,497	$31,136,093	$32,360,532	$33,173,165	$32,506,579	$29,897,891	$18,852,407	
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$83,660,765	$75,947,687	$68,288,176	$63,928,198	$61,147,574	$59,894,635	$61,178,587	$63,498,664	$65,535,813	$65,681,928	$62,406,659	$48,752,378	
4. Average True-Up Amount (Line 3 x 1/2)	$41,830,382	$37,973,843	$34,144,088	$31,964,099	$30,573,787	$29,947,318	$30,589,293	$31,749,332	$32,767,907	$32,840,964	$31,203,329	$24,376,189	
5. Interest Rate (First Day of Reporting Month)[1]	1.59000%	1.64000%	1.56000%	2.21000%	0.06000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	
6. Interest Rate (First Day of Subsequent Month)[1]	1.64000%	1.56000%	2.21000%	0.06000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.23000%	3.20000%	3.77000%	2.27000%	0.14000%	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	
8. Average Interest Rate (Line 7 x 1/2)	1.61500%	1.60000%	1.88500%	1.13500%	0.07000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.13458%	0.13333%	0.15708%	0.09458%	0.00583%	0.00667%	0.00667%	0.00667%	0.00667%	0.00667%	0.00667%	0.00667%	
10. Interest Provision for the Month (Line 4 x Line 9)	$56,297	$50,632	$53,635	$30,233	$1,783	$1,996	$2,039	$2,117	$2,185	$2,189	$2,080	$1,625	$206,813

[1] Actual interest rates are developed using the AA financial 30-day rates as published by the Federal Reserve. Estimated interest rates are based on the actual rates for June 2020.

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

FORM: 42-4E-1

JANUARY 2020 THROUGH DECEMBER 2020

VARIANCE REPORT OF O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)
PROJECT #	ECRC - 2020 Actual Estimated Filing [b]	ECRC - 2020 Projection Filing [c]	Dif ECRC - 2020 Projection Filing [d]	% Dif ECRC - Projection Filing [e]
1 - Air Operating Permit Fees	$157,384	$215,382	($57,998)	(26.9%)
3a - Continuous Emission Monitoring Systems	$384,047	$343,215	$40,832	11.9%
5a - Maintenance of Stationary Above Ground Fuel Storage T	$511,197	$596,202	($85,005)	(14.3%)
8a - Oil Spill Clean-up/Response Equipment	$360,809	$173,313	$187,496	108.2%
14 - NPDES Permit Fees	$69,200	$57,700	$11,500	19.9%
19a - Substation Pollutant Discharge Prevention & Removal -	$3,556,993	$2,690,446	$866,547	32.2%
19b - Substation Pollutant Discharge Prevention & Removal -	$1,285,675	$1,008,270	$277,405	27.5%
21 - St. Lucie Turtle Nets	$299,282	$368,400	($69,118)	(18.8%)
NA-Amortization of Gains on Sales of Emissions Allowances	($73)	($88)	$15	(16.7%)
22 - Pipeline Integrity Management	$327,500	$327,500	$0	0.0%
23 - SPCC - Spill Prevention, Control & Countermeasures	$785,841	$794,938	($9,097)	(1.1%)
24 - Manatee Reburn	$23,672	$113,517	($89,845)	(79.1%)
27 - Lowest Quality Water Source	$107,675	$156,000	($48,325)	(31.0%)
28 - CWA 316(b) Phase II Rule	$1,068,913	$955,862	$113,051	11.8%
29 - SCR Consumables	$637,223	$531,502	$105,721	19.9%
31 - Clean Air Interstate Rule (CAIR) Compliance	$3,833,259	$5,641,945	($1,808,686)	(32.1%)
33 - MATS Project	$1,888,540	$2,648,335	($759,795)	(28.7%)
35 - Martin Plant Drinking Water System Compliance	$10,492	$0	$10,492	N/A
37 - DeSoto Next Generation Solar Energy Center	$670,971	$840,515	($169,545)	(20.2%)
38 - Space Coast Next Generation Solar Energy Center	$268,593	$276,067	($7,474)	(2.7%)
39 - Martin Next Generation Solar Energy Center	$4,747,474	$4,745,852	$1,622	0.0%
41 - Manatee Temporary Heating System	$152,070	$195,900	($43,830)	(22.4%)
42 - Turkey Point Cooling Canal Monitoring Plan	$19,694,511	$18,635,320	$1,059,191	5.7%
45 - 800 MW Unit ESP	$154,969	$260,689	($105,720)	(40.6%)
47 - NPDES Permit Renewal Requirements	$93,797	$81,154	$12,643	15.6%
48 - Industrial Boiler MACT	$32,668	$32,500	$168	0.5%
50 - Steam Electric Effluent Guidelines Revised Rules	$4,608	$0	$4,608	N/A
51 - Gopher Tortoise Relocations	$28,732	$25,649	$3,083	12.0%
54 - Coal Combustion Residuals	$0	$1,600,768	($1,600,768)	(100.0%)
123-PROTECTED SPECIES PROJECT	$34,000	$0	$34,000	N/A
Total	$41,190,022	$43,316,853	($2,126,831)	(4.9%)

[b] The 12-Month Totals on Form 42-5E

[c] As approved in Order No. PSC-2019-0500-FOF-EI issued November 22, 2019.

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

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

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

FORM: 42-4E-2

JANUARY 2020 THROUGH DECEMBER 2020

(2)	(3)	(4)	(5)	(6)
	ECRC - 2020 Actual Estimated Filing [b]	ECRC - 2020 Projection Filing [c]	Dif. ECRC - 2020 Projection Filing [d]	% Dif. ECRC - 2020 Projection Filing [e]
2. Total of O&M Activities	$41,190,022	$43,316,853	($2,126,831)	(4.9%)
3. Recoverable Costs Allocated to Energy	$27,286,411	$28,759,030	($1,472,619)	(5.1%)
4a. Recoverable Costs Allocated to CP Demand	$10,346,618	$11,867,377	($1,520,759)	(12.8%)
4b. Recoverable Costs Allocated to GCP Demand	$3,556,993	$2,690,446	$866,547	32.2%
5. Jurisdictional Energy Recoverable Costs	$26,137,392	$27,552,189	($1,414,797)	(5.1%)
6a. Jurisdictional CP Demand Recoverable Costs	$9,750,876	$11,221,484	($1,470,608)	(13.1%)
6b. Jurisdictional GCP Demand Recoverable Costs	$3,556,993	$2,690,446	$866,547	32.2%
7. Total Jurisdictional Recoverable Costs for O&M Activities	$39,445,262	$41,464,119	($2,018,857)	4.9%)

[b] The 12-Month Totals on Form 42-5E

[c] As approved in Order No. PSC-2019-0500-FOF-EI issued November 22, 2019.

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

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

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

JANUARY 2020 THROUGH DECEMBER 2020

O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
O&M Project	Strata	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1 - Air Operating Permit Fees	Base	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$133,620
1 - Air Operating Permit Fees	Intermediate	$1,800	$1,800	$2,158	$4,645	$4,645	$4,731	$4,731	$4,731	$4,731	$4,731	$4,731	$4,731	$48,166
1 - Air Operating Permit Fees	Peaking	$263	$263	($28,063)	$263	$263	$372	$372	$372	$372	$372	$372	$372	($24,402)
3a - Continuous Emission Monitoring Systems	Intermediate	$78,268	$10,799	$16,018	$34,346	$23,563	$26,198	$13,431	$25,574	$13,431	$20,098	$18,907	$33,988	$314,621
3a - Continuous Emission Monitoring Systems	Peaking	$34,861	$1,197	($263)	$325	$191	$2,852	$2,837	$2,867	$2,852	$2,837	$2,852	$16,019	$69,427
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$0	$0	$5,846	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,846
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$1,185	$3,027	$7,152	$187	$2,685	$11,700	$0	$1	$1	$41,494	$39,367	$0	$106,799
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$1,914	$3,846	$0	$1,403	$5,043	$1	$112,330	$0	$0	$128,507	$145,508	$0	$398,552
8a - Oil Spill Clean-up/Response Equipment	Base	$0	$0	$0	$55	($55)	$0	$0	$0	$0	$0	$0	$16	$15
8a - Oil Spill Clean-up/Response Equipment	Intermediate	($2,610)	$862	$1,597	$784	$238	$2,207	$2,207	$2,207	$3,069	$11,007	$14,857	$3,303	$39,730
8a - Oil Spill Clean-up/Response Equipment	Peaking	($21,118)	$6,974	$12,920	$6,632	$1,637	$17,793	$17,793	$17,793	$24,767	$88,993	$120,143	$26,740	$321,064
14 - NPDES Permit Fees	Base	$11,500	$2,585	$0	$0	($2,585)	$0	$0	$0	$0	$0	$0	$0	$11,500
14 - NPDES Permit Fees	Intermediate	$28,260	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,260
14 - NPDES Permit Fees	Peaking	$29,440	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29,440
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$260,603	$484,062	$496,230	$674,771	$350,779	$198,137	$198,137	$198,137	$198,137	$166,000	$166,000	$166,000	$3,556,993
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$13,313	$72,809	$77,617	$221,174	$397,476	$60,445	$60,445	$70,445	$70,445	$80,502	$80,502	$80,502	$1,285,675
21 - St. Lucie Turtle Nets	Base	($12,785)	$15,475	$6,510	$48,406	$26,775	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$299,282
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($1)	($1)	($1)	$0	$0	($7)	($7)	($7)	($7)	($7)	($7)	($7)	($54)
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	($4)	($4)	($4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12)
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	($2)	($2)	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6)
22 - Pipeline Integrity Management	Intermediate	$0	$12	$0	$0	$0	$0	$0	$0	$0	$130,716	$5,161	$0	$135,890
22 - Pipeline Integrity Management	Peaking	$0	$18	$0	$0	$0	$0	$0	$0	$0	$184,315	$7,278	$0	$191,610
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$51,630	$61,863	$68,510	$73,741	$41,884	$47,167	$47,167	$47,167	$47,167	$47,167	$47,167	$47,167	$627,795
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$0	$1,408	$4,192	$1,965	($5,156)	$768	$2,268	$2,268	$1,068	$1,068	$768	$1,391	$12,010
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$0	$680	$24	$0	$164	$532	$532	$532	$532	$532	$532	$2,909	$6,966
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$9,165	$27,525	$8,049	$11,735	$9,896	$10,300	$10,300	$10,300	$10,300	$10,300	$10,300	$10,900	$139,071
24 - Manatee Reburn	Peaking	$3,165	$15,302	$96	$4,887	$222	$0	$0	$0	$0	$0	$0	$0	$23,672
27 - Lowest Quality Water Source	Intermediate	$11,398	$8,826	$9,007	$8,042	$7,957	$8,526	$8,900	$9,000	$8,900	$9,000	$9,043	$9,076	$107,675
28 - CWA 316(b) Phase II Rule	Base	$6,484	$5,648	$6,547	$19,138	$4,956	$1,269	$15,878	$15,844	$34,976	$47,766	$43,483	$43,575	$245,562
28 - CWA 316(b) Phase II Rule	Intermediate	$66,524	$62,577	$94,433	$57,257	$91,533	$103,214	$88,870	$68,847	$59,282	$58,831	$20,852	$6,289	$778,508
28 - CWA 316(b) Phase II Rule	Peaking	$376	($6,073)	$692	$721	$5,868	$7,565	$7,821	$5,370	$5,626	$5,626	$5,370	$5,881	$44,842
29 - SCR Consumables	Intermediate	$153,282	$5,143	$15,013	$15,180	$20,556	$23,326	$87,736	$93,053	$64,671	$64,671	$64,671	$29,922	$637,223
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$276,381	$295,376	$317,954	$439,096	$427,619	$391,699	$232,573	$280,773	$260,248	$256,667	$256,660	$261,077	$3,696,122
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$9,444	$9,577	$14,040	$16,046	$10,050	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,980	$137,137
33 - MATS Project	Base	$278,093	$36,242	$61,096	$56,985	$119,863	$2,153	$381,458	$186,958	$189,486	$189,628	$189,605	$196,974	$1,888,540
35 - Martin Plant Drinking Water System Compliance	Peaking	$0	$2,673	$2,607	$2,713	$0	$2,500	$0	$0	$0	$0	$0	$0	$10,492
37 - DeSoto Next Generation Solar Energy Center	Solar	$42,764	$39,408	$29,698	$48,240	($5,725)	$108,206	$72,082	$60,531	$61,628	$76,156	$60,673	$77,309	$670,971
38 - Space Coast Next Generation Solar Energy Center	Solar	$17,828	$21,617	$16,657	$37,522	$9,725	$31,276	$33,770	$33,297	$19,668	$12,276	$15,289	$19,670	$268,593
39 - Martin Next Generation Solar Energy Center	Intermediate	$432,285	$1,166,061	$76,194	$328,349	$306,532	$337,293	$283,009	$271,578	$307,293	$278,065	$659,256	$301,560	$4,747,474
41 - Manatee Temporary Heating System	Intermediate	$20,365	($6,821)	$7,301	($174)	$45,264	$5,000	$20,135	$5,000	$5,000	$15,000	$16,000	$20,000	$152,070
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$925,279	$1,002,025	$906,034	$502,844	$772,915	$972,569	$841,610	$1,055,009	$1,078,998	$1,024,867	$876,482	$9,724,531	$19,683,162
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$0	$2,935	$0	$3,473	$4,941	$0	$0	$0	$0	$0	$0	$0	$11,349
45 - 800 MW Unit ESP	Peaking	$360	$32,144	$0	$107	$50	$16,622	$16,622	$16,622	$16,622	$16,622	$16,622	$22,576	$154,969
47 - NPDES Permit Renewal Requirements	Base	$35,262	($2,778)	$12,587	($997)	$13,499	$0	$0	$0	$0	$2,585	$0	$0	$60,159
47 - NPDES Permit Renewal Requirements	Intermediate	$0	$0	$7,450	$2,513	$8,512	$0	$0	$0	$7,450	$5,200	$0	$2,513	$33,638
48 - Industrial Boiler MACT	Base	$0	$45	$0	$0	$27	$0	$0	$0	$0	$5,155	$0	$0	$5,227
48 - Industrial Boiler MACT	Peaking	$0	$235	$0	$0	$141	$0	$0	$0	$0	$27,065	$0	$0	$27,441
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$229	$1,695	$238	$19	$2,033	$0	$0	$0	$0	$0	$0	$0	$4,215
50 - Steam Electric Effluent Guidelines Revised Rules	Peaking	$393	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$393
51 - Gopher Tortoise Relocations	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000	$2,000
51 - Gopher Tortoise Relocations	Peaking	$0	$0	$0	$0	$0	$0	$10,732	$8,000	$8,000	$0	$0	$0	$26,732
123-Protected Species Project	Intermediate	$0	$0	$0	$0	$0	$0	$34,000	$0	$0	$0	$0	$0	$34,000
	Total	$2,776,728	$3,398,190	$2,267,268	$2,633,528	$2,715,114	$2,447,249	$2,660,571	$2,545,102	$2,557,546	$3,066,647	$2,951,278	$11,170,800	$41,190,022

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

JANUARY 2020 THROUGH DECEMBER 2020

O&M ACTIVITIES

O&M Project	Strata	Monthly Data	Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand	GCP Demand
1 - Air Operating Permit Fees	Base	$133,620	95.8799%	$128,115	$128,115	$0	$0
1 - Air Operating Permit Fees	Intermediate	$48,166	94.2430%	$45,393	$45,393	$0	$0
1 - Air Operating Permit Fees	Peaking	($24,402)	95.1325%	($23,214)	($23,214)	$0	$0
3a - Continuous Emission Monitoring Systems	Intermediate	$314,621	94.2430%	$296,508	$296,508	$0	$0
3a - Continuous Emission Monitoring Systems	Peaking	$69,427	95.1325%	$66,047	$66,047	$0	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$5,846	95.7922%	$5,600	$0	$5,600	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$106,799	94.1569%	$100,558	$0	$100,558	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$398,552	95.0455%	$378,806	$0	$378,806	$0
8a - Oil Spill Clean-up/Response Equipment	Base	$15	95.8799%	$15	$15	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Intermediate	$39,730	94.2430%	$37,442	$37,442	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Peaking	$321,064	95.1325%	$305,437	$305,437	$0	$0
14 - NPDES Permit Fees	Base	$11,500	95.7922%	$11,016	$0	$11,016	$0
14 - NPDES Permit Fees	Intermediate	$28,260	94.1569%	$26,609	$0	$26,609	$0
14 - NPDES Permit Fees	Peaking	$29,440	95.0455%	$27,981	$0	$27,981	$0
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$3,556,993	100.0000%	$3,556,993	$0	$0	$3,556,993
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$1,285,675	89.9387%	$1,156,319	$0	$1,156,319	$0
21 - St. Lucie Turtle Nets	Base	$299,282	95.7922%	$286,689	$0	$286,689	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($54)	95.8799%	($52)	($52)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	($12)	94.2430%	($12)	($12)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	($6)	95.1325%	($6)	($6)	$0	$0
22 - Pipeline Integrity Management	Intermediate	$135,890	94.1569%	$127,950	$0	$127,950	$0
22 - Pipeline Integrity Management	Peaking	$191,610	95.0455%	$182,116	$0	$182,116	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$12,010	94.1569%	$11,308	$0	$11,308	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$6,966	95.0455%	$6,621	$0	$6,621	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$627,795	100.0000%	$627,795	$0	$627,795	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$139,071	89.9387%	$125,078	$0	$125,078	$0
24 - Manatee Reburn	Peaking	$23,672	95.1325%	$22,519	$22,519	$0	$0
27 - Lowest Quality Water Source	Intermediate	$107,675	94.1569%	$101,383	$0	$101,383	$0
28 - CWA 316(b) Phase II Rule	Base	$245,562	95.7922%	$235,230	$0	$235,230	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$778,508	94.1569%	$733,019	$0	$733,019	$0
28 - CWA 316(b) Phase II Rule	Peaking	$44,842	95.0455%	$42,621	$0	$42,621	$0
29 - SCR Consumables	Intermediate	$637,223	94.2430%	$600,538	$600,538	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,696,122	95.8799%	$3,543,838	$3,543,838	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$137,137	95.1325%	$130,462	$130,462	$0	$0
33 - MATS Project	Base	$1,888,540	95.8799%	$1,810,731	$1,810,731	$0	$0
35 - Martin Plant Drinking Water System Compliance	Peaking	$10,492	95.0455%	$9,972	$0	$9,972	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$670,971	95.7922%	$642,738	$0	$642,738	$0
38 - Space Coast Next Generation Solar Energy Center	Solar	$268,593	95.7922%	$257,292	$0	$257,292	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$4,747,474	94.1569%	$4,470,072	$0	$4,470,072	$0
41 - Manatee Temporary Heating System	Intermediate	$152,070	94.2430%	$143,315	$143,315	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$19,683,162	95.8799%	$18,872,195	$18,872,195	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$11,349	94.2430%	$10,695	$10,695	$0	$0
45 - 800 MW Unit ESP	Peaking	$154,969	95.1325%	$147,426	$147,426	$0	$0
47 - NPDES Permit Renewal Requirements	Base	$60,159	95.7922%	$57,628	$0	$57,628	$0
47 - NPDES Permit Renewal Requirements	Intermediate	$33,638	94.1569%	$31,672	$0	$31,672	$0
47 - NPDES Permit Renewal Requirements	Peaking	$0	95.0455%	$0	$0	$0	$0
48 - Industrial Boiler MACT	Base	$5,227	95.7922%	$5,007	$0	$5,007	$0
48 - Industrial Boiler MACT	Peaking	$27,441	95.0455%	$26,082	$0	$26,082	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$4,215	95.7922%	$4,037	$0	$4,037	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Peaking	$393	95.0455%	$374	$0	$374	$0
51 - Gopher Tortoise Relocations	Intermediate	$2,000	94.1569%	$1,883	$0	$1,883	$0
51 - Gopher Tortoise Relocations	Peaking	$26,732	95.0455%	$25,407	$0	$25,407	$0
123-Protected Species Project	Intermediate	$34,000	94.1569%	$32,013	$0	$32,013	$0
	Total	$41,190,022		$39,445,262	$26,137,392	$9,750,876	$3,556,993

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

FORM: 42-5E-2

JANUARY 2020 THROUGH DECEMBER 2020

O&M ACTIVITIES

	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	2020
2. Total of O&M Activities	$2,776,728	$3,398,190	$2,267,268	$2,633,528	$2,715,114	$2,447,249	$2,660,571	$2,545,102	$2,557,546	$3,066,647	$2,951,278	$11,170,800	$41,190,022
3. Recoverable Costs Allocated to Energy - Base	$1,490,886	$1,344,777	$1,296,218	$1,010,115	$1,331,477	$1,377,549	$1,466,768	$1,533,867	$1,539,859	$1,482,289	$1,333,874	$10,193,726	$25,401,406
Recoverable Costs Allocated to Energy - Intermediate	$251,101	$14,714	$42,082	$58,254	$99,207	$61,462	$128,240	$130,565	$90,902	$115,507	$119,166	$91,945	$1,203,145
Recoverable Costs Allocated to Energy - Peaking	$26,973	$65,455	($1,273)	$28,260	$12,413	$48,639	$48,625	$48,654	$55,613	$119,825	$150,989	$77,687	$681,861
Recoverable Costs Allocated to Energy - Solar	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$22,477	$100,335	$85,667	$232,909	$407,372	$70,745	$70,745	$80,745	$80,745	$90,802	$90,802	$91,402	$1,424,745
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$40,690	$22,671	$31,728	$66,567	$44,705	$31,969	$46,578	$46,544	$65,676	$86,206	$74,183	$74,275	$631,791
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$539,653	$1,241,911	$198,427	$398,313	$412,061	$461,502	$417,047	$351,694	$383,995	$524,375	$734,447	$322,829	$5,986,254
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$32,123	$1,378	$3,323	$4,837	$11,216	$10,598	$131,414	$13,902	$14,157	$346,043	$158,688	$8,791	$736,468
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$60,592	$61,024	$46,355	$85,762	$4,000	$139,482	$105,851	$93,828	$81,296	$88,432	$75,962	$96,979	$939,564
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$51,630	$61,863	$68,510	$73,741	$41,884	$47,167	$47,167	$47,167	$47,167	$47,167	$47,167	$47,167	$627,795
5. Recoverable Costs Jurisdictionalized on GCP Demand - Distribution	$260,603	$484,062	$496,230	$674,771	$350,779	$198,137	$198,137	$198,137	$198,137	$166,000	$166,000	$166,000	$3,556,993
6. Retail Production Energy Jurisdictional Factor - Base	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	
Retail Production Energy Jurisdictional Factor - Intermediate	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	
Retail Production Energy Jurisdictional Factor - Peaking	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	
Retail Production Energy Jurisdictional Factor - Solar	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	
7. Retail Distribution Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
Retail Transmission Demand Jurisdictional Factor	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	
Retail Production Demand Jurisdictional Factor - Base	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	
Retail Production Demand Jurisdictional Factor - Intermediate	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	
Retail Production Demand Jurisdictional Factor - Peaking	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	
Retail Production Demand Jurisdictional Factor - Solar	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	
8. Jurisdictional Recoverable Costs- Transmission	$20,216	$90,240	$77,048	$209,475	$366,385	$63,627	$63,627	$72,621	$72,621	$81,666	$81,666	$82,206	$1,281,397
Jurisdictional Recoverable Costs - Production - Base	$1,468,438	$1,311,088	$1,273,205	$1,032,263	$1,319,443	$1,351,416	$1,450,953	$1,515,256	$1,539,327	$1,503,796	$1,349,979	$9,844,883	$24,960,048
Jurisdictional Recoverable Costs - Production - Intermediate	$744,765	$1,183,211	$226,493	$429,939	$481,479	$492,459	$513,536	$454,193	$447,226	$602,592	$803,838	$390,617	$6,770,348
Jurisdictional Recoverable Costs - Production - Peaking	$56,191	$63,579	$1,948	$31,482	$22,469	$56,344	$171,161	$59,498	$66,362	$442,891	$294,465	$82,261	$1,348,651
Jurisdictional Recoverable Costs - Production - Solar	$58,042	$58,457	$44,405	$82,154	$3,831	$133,613	$101,398	$89,880	$77,875	$84,711	$72,766	$92,898	$900,029
Jurisdictional Recoverable Costs - Distribution	$312,233	$545,925	$564,740	$748,511	$392,663	$245,304	$245,304	$245,304	$245,304	$213,167	$213,167	$213,167	$4,184,788
9. Total Jurisdictional Recoverable Costs for O&M Activities	$2,659,886	$3,252,499	$2,187,838	$2,533,824	$2,586,271	$2,342,763	$2,545,978	$2,436,751	$2,448,715	$2,928,823	$2,815,881	$10,706,032	$39,445,262

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

FORM: 42-6E

JANUARY 2020 THROUGH DECEMBER 2020

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

Capital Project #	ECRC - 2020 Actual Estimated Filing (b)	ECRC - 2020 Projection Filing (c)	Dif ECRC - 2020 Projection Filing (d)	% Dif ECRC - 2020 Projection Filing (e)
02 - Low NOX Burner Technology	$57,069	$57,311	($242)	(0%)
03 - Continuous Emission Monitoring Systems	$467,855	$481,673	($13,817)	(3%)
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,660,195	$1,603,770	$56,424	4%
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,535	$1,535	$1	0%
08 - Oil Spill Clean-up/Response Equipment	$195,267	$335,970	($140,703)	(42%)
10 - Relocate Storm Water Runoff	$6,215	$6,259	($44)	(1%)
12 - Scherer Discharge Pipeline	$33,749	$33,978	($229)	(1%)
20 - Wastewater Discharge Elimination & Reuse	$42,408	$42,940	($531)	(1%)
21 - St. Lucie Turtle Nets	$734,751	$742,000	($7,250)	(1%)
22 - Pipeline Integrity Management	$263,403	$265,742	($2,340)	(1%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$2,221,898	$2,267,961	($46,064)	(2%)
24 - Manatee Reburn	$2,979,301	$2,997,332	($18,031)	(1%)
26 - UST Remove/Replacement	$6,651	$6,713	($62)	(1%)
28 - CWA 316(b) Phase II Rule	$77,810	$295,116	($217,305)	(74%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$45,144,078	$45,519,130	($375,052)	(1%)
33 - MATS Project	$9,423,322	$9,593,092	($169,770)	(2%)
34 - St Lucie Cooling Water System Inspection & Maintenance	$354,911	$455,101	($100,190)	(22%)
35 - Martin Plant Drinking Water System Compliance	$20,188	$20,366	($178)	(1%)
36 - Low-Level Radioactive Waste Storage	$1,653,138	$1,667,815	($14,677)	(1%)
37 - DeSoto Next Generation Solar Energy Center	$11,943,760	$12,202,704	($258,944)	(2%)
38 - Space Coast Next Generation Solar Energy Center	$5,561,296	$5,683,383	($122,087)	(2%)
39 - Martin Next Generation Solar Energy Center	$34,080,447	$34,650,825	($570,378)	(2%)
41 - Manatee Temporary Heating System	$3,338,462	$3,236,776	$101,686	3%
42 - Turkey Point Cooling Canal Monitoring Plan	$6,058,054	$6,462,269	($404,215)	(6%)
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$14,606	$14,736	($131)	(1%)
45 - 800 MW Unit ESP	$18,821,748	$18,972,586	($150,838)	(1%)
47 - NPDES Permit Renewal Requirements	$53,039	$27,667	$25,372	92%
50 - Steam Electric Effluent Guidelines Revised Rules	$99,788	$144,266	($44,478)	(31%)
54 - Coal Combustion Residuals	$9,951,398	$9,404,214	$547,184	6%
NA-Amortization of Gains on Sales of Emissions Allowances	($17)	($22)	$5	(22%)
Total Investment Projects - Recoverable Costs	$155,266,324	$157,193,209	($1,926,885)	(1.2%)

(b) The 12-Month Totals on Form 42-7E

(c) As approved in Order No. PSC-2019-0500-FOF-EI issued November 22, 2019.

(d) Column (2) - Column (3)

(e) Column (4) / Column (3)

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

FORM: 42-6E

JANUARY 2020 THROUGH DECEMBER 2020

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

	ECRC - 2020 Actual/Estimated (b)	ECRC - 2020 Projection (c)	Dif. ECRC - 2020 Projection Filing (d)	% Dif. ECRC - 2020 Projection Filing (e)
2. Total Investment Projects - Recoverable Costs	$155,266,324	$157,193,209	$1,926,885	1.24%
3. Recoverable Costs Allocated to Energy	$3,504,208	$3,536,293	$32,085	0.92%
4. Recoverable Costs Allocated to Demand	$151,762,116	$153,656,916	$1,894,800	1.25%
5. Jurisdictional Energy Recoverable Costs	$13,066,647	$13,227,054	$160,407	1.23%
8. Jurisdictional Demand Recoverable Costs	$134,776,648	$136,455,754	$1,679,106	1.25%
9. Total Jurisdictional Recoverable Costs for Investment Projects	$147,843,295	$149,682,808	$1,839,513	1.24%

(b) The 12-Month Totals on Form 42-7E

(c) As approved in Order No. PSC-2019-0500-FOF-EI issued November 22, 2019.

(d) Column (2) - Column (3)

(e) Column (4) / Column (3)

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

JANUARY 2020 THROUGH DECEMBER 2020

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Capital Project (a)	Strata	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
02 - Low NOX Burner Technology	Peaking	$4,876	$4,855	$4,834	$4,813	$4,792	$4,771	$4,740	$4,719	$4,698	$4,678	$4,657	$4,636	$57,069
03 - Continuous Emission Monitoring Systems	Base	$2,350	$2,342	$2,334	$2,326	$2,318	$2,310	$2,294	$2,286	$2,278	$2,271	$2,263	$2,255	$27,625
03 - Continuous Emission Monitoring Systems	Intermediate	$23,271	$23,203	$23,134	$23,065	$22,997	$22,930	$22,777	$22,710	$22,643	$22,576	$22,508	$22,415	$274,230
03 - Continuous Emission Monitoring Systems	Peaking	$14,089	$14,047	$14,005	$13,963	$13,921	$13,879	$13,787	$13,745	$13,704	$13,662	$13,620	$13,579	$166,000
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$150	$150	$150	$150	$150	$150	$149	$149	$149	$149	$149	$149	$1,797
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$58,947	$58,908	$58,869	$58,822	$58,775	$58,729	$59,825	$61,254	$61,186	$61,118	$61,050	$60,982	$718,464
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$19,065	$19,004	$18,944	$18,883	$18,823	$18,762	$18,638	$18,578	$18,518	$18,458	$18,398	$18,338	$224,408
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$60,970	$60,741	$60,511	$60,282	$60,053	$59,824	$59,427	$59,199	$58,971	$58,744	$58,516	$58,288	$715,525
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$133	$132	$131	$130	$129	$128	$128	$127	$126	$125	$124	$123	$1,535
08 - Oil Spill Clean-up/Response Equipment	Distribution	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$265
08 - Oil Spill Clean-up/Response Equipment	General	$28	$28	$28	$28	$28	$28	$27	$27	$27	$27	$27	$27	$330
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$9,426	$10,347	$10,334	$10,308	$10,292	$10,277	$10,209	$10,180	$10,151	$10,516	$11,121	$11,328	$124,488
08 - Oil Spill Clean-up/Response Equipment	Peaking	$5,975	$5,866	$5,852	$5,829	$5,806	$5,784	$5,783	$5,798	$5,775	$5,752	$5,912	$6,051	$70,184
10 - Relocate Storm Water Runoff	Base	$527	$526	$524	$523	$521	$520	$516	$515	$513	$512	$510	$509	$6,215
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($2)	($2)	($1)	($1)	($1)	($2)	($1)	($1)	($1)	($1)	($1)	($1)	($17)
12 - Scherer Discharge Pipeline	Base	$2,864	$2,856	$2,847	$2,839	$2,830	$2,822	$2,803	$2,795	$2,786	$2,778	$2,769	$2,761	$33,749
20 - Wastewater Discharge Elimination & Reuse	Peaking	$3,546	$3,546	$3,546	$3,546	$3,546	$3,546	$3,522	$3,522	$3,522	$3,522	$3,522	$3,522	$42,408
21 - St. Lucie Turtle Nets	Base	$61,864	$61,778	$61,692	$61,605	$61,519	$61,432	$61,025	$60,939	$60,853	$60,767	$60,681	$60,595	$734,751
22 - Pipeline Integrity Management	Intermediate	$11,911	$11,888	$11,866	$11,843	$11,821	$11,798	$11,720	$11,697	$11,675	$11,653	$11,630	$11,608	$141,109
22 - Pipeline Integrity Management	Peaking	$10,324	$10,304	$10,285	$10,265	$10,245	$10,225	$10,157	$10,137	$10,118	$10,098	$10,078	$10,058	$122,293
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$28,795	$28,713	$28,631	$28,549	$28,467	$28,385	$28,197	$28,116	$28,034	$27,953	$27,871	$27,790	$339,502
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$22,279	$22,245	$22,212	$22,179	$22,161	$22,227	$22,165	$22,130	$22,096	$22,062	$22,051	$22,040	$265,847
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$910	$909	$908	$907	$905	$904	$898	$897	$896	$895	$893	$892	$10,814
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$56,442	$56,637	$56,829	$56,675	$56,520	$56,374	$56,147	$56,780	$58,034	$60,162	$61,943	$62,719	$695,260
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$45,833	$45,859	$45,712	$45,565	$45,400	$45,235	$44,935	$44,771	$44,607	$44,443	$44,279	$44,115	$540,754
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$31,134	$31,088	$31,047	$31,002	$30,958	$30,914	$30,699	$30,664	$30,620	$30,576	$30,532	$30,488	$369,721
24 - Manatee Plant Reburn	Peaking	$253,352	$252,500	$251,649	$250,797	$249,946	$249,094	$247,442	$246,596	$245,750	$244,904	$244,058	$243,212	$2,979,301
26 - UST Remove/Replacement	General	$561	$560	$559	$558	$557	$556	$552	$551	$550	$550	$549	$548	$6,651
28 - CWA 316(b) Phase II Rule	Intermediate	$6,563	$6,552	$6,540	$6,529	$6,517	$6,506	$6,462	$6,451	$6,440	$6,428	$6,417	$6,405	$77,810
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,044,156	$3,039,240	$3,038,950	$3,038,692	$3,034,338	$3,030,407	$3,011,497	$3,006,579	$3,001,300	$2,996,022	$2,990,743	$2,987,196	$36,219,119
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$8	$8	$103
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$9,563	$9,546	$9,530	$9,514	$9,498	$9,481	$9,418	$9,402	$9,386	$9,370	$9,354	$9,338	$113,401
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$743,837	$742,414	$740,991	$739,567	$738,144	$736,721	$731,831	$730,417	$729,004	$727,590	$726,176	$724,763	$8,811,455
33 - MATS Project	Base	$783,097	$781,508	$795,626	$793,928	$792,230	$790,531	$785,285	$783,597	$781,910	$780,223	$778,536	$776,849	$9,423,322
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$29,675	$29,675	$29,675	$29,675	$29,675	$29,675	$29,477	$29,477	$29,477	$29,477	$29,477	$29,477	$354,911
35 - Martin Plant Drinking Water System Compliance	Intermediate	$971	$970	$968	$966	$964	$962	$956	$954	$952	$950	$948	$946	$11,507
35 - Martin Plant Drinking Water System Compliance	Peaking	$733	$731	$730	$729	$727	$726	$721	$720	$718	$717	$715	$714	$8,681
36 - Low-Level Radioactive Waste Storage	Base	$139,550	$139,284	$139,017	$138,751	$138,485	$138,218	$137,301	$137,036	$136,771	$136,506	$136,242	$135,977	$1,653,138
37 - DeSoto Next Generation Solar Energy Center	Solar	$1,018,746	$1,015,486	$1,012,372	$1,009,098	$1,005,634	$1,002,315	$988,163	$984,801	$981,591	$978,376	$975,165	$972,012	$11,943,760
38 - Space Coast Next Generation Solar Energy Center	Solar	$473,913	$472,478	$471,046	$469,611	$468,172	$466,736	$460,436	$458,855	$457,223	$455,687	$454,275	$452,864	$5,561,296
39 - Martin Next Generation Solar Energy Center	Intermediate	$2,890,502	$2,884,352	$2,879,010	$2,873,516	$2,866,652	$2,860,096	$2,820,790	$2,814,108	$2,807,357	$2,800,605	$2,794,221	$2,789,239	$34,080,447
41 - Manatee Temporary Heating System	Distribution	$1,518	$1,518	$1,518	$1,518	$1,518	$1,518	$1,508	$1,508	$1,508	$1,508	$1,508	$1,508	$18,161
41 - Manatee Temporary Heating System	Intermediate	$154,039	$153,729	$153,095	$152,462	$265,674	$277,658	$275,817	$274,517	$273,216	$271,916	$270,615	$269,315	$2,792,055
41 - Manatee Temporary Heating System	Peaking	$129,531	$129,147	$128,475	$127,803	$13,289	$0	$0	$0	$0	$0	$0	$0	$528,245
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$462,688	$468,459	$470,238	$474,505	$429,258	$384,925	$389,807	$394,565	$403,023	$408,940	$408,287	$413,136	$5,107,831
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$0	$0	$0	$0	$63,923	$127,751	$126,903	$126,711	$126,520	$126,329	$126,138	$125,947	$950,223
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$703	$701	$700	$699	$697	$696	$691	$690	$689	$688	$686	$685	$8,325
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$530	$529	$528	$527	$526	$525	$522	$521	$520	$519	$518	$517	$6,280
45 - 800 MW Unit ESP	Intermediate	$719	$716	$713	$711	$708	$705	$701	$698	$695	$693	$690	$687	$8,436
45 - 800 MW Unit ESP	Peaking	$1,585,780	$1,583,754	$1,581,832	$1,578,958	$1,576,081	$1,573,204	$1,562,761	$1,559,904	$1,557,046	$1,554,188	$1,551,331	$1,548,473	$18,813,313
47 - NPDES Permit Renewal Requirements	Base	$0	$0	$0	$0	$8	$282	$1,956	$4,778	$8,340	$10,897	$12,347	$14,432	$53,039
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$6,556	$6,658	$6,867	$7,245	$7,736	$8,117	$8,381	$8,700	$9,019	$9,337	$9,656	$11,516	$99,788
54 - Coal Combustion Residuals	Base	$777,438	$778,972	$772,783	$779,875	$787,503	$827,077	$859,445	$862,525	$865,604	$868,683	$871,762	$899,731	$9,951,398
	Total	$12,990,460	$12,975,480	$12,968,667	$12,960,359	$12,961,467	$12,996,465	$12,929,421	$12,916,426	$12,906,620	$12,894,626	$12,875,549	$12,890,784	$155,266,324

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

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

JANUARY 2020 THROUGH DECEMBER 2020

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

Capital Project	Strata	Monthly Data	Jurisdictionalization		Method of Classification	
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	CP Demand	Energy
02 - Low NOX Burner Technology	Peaking	$57,069	95.1325%	$54,291	$0	$54,291
03 - Continuous Emission Monitoring Systems	Base	$27,625	95.8799%	$26,486	$0	$26,486
03 - Continuous Emission Monitoring Systems	Intermediate	$274,230	94.2430%	$258,443	$0	$258,443
03 - Continuous Emission Monitoring Systems	Peaking	$166,000	95.1325%	$157,920	$0	$157,920
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$1,797	95.7922%	$1,721	$1,589	$132
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$718,464	96.9124%	$696,280	$642,720	$53,560
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$224,408	94.1569%	$211,296	$195,042	$16,254
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$715,525	95.0455%	$680,074	$627,761	$52,313
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$1,535	95.7922%	$1,471	$1,358	$113
08 - Oil Spill Clean-up/Response Equipment	Distribution	$265	100.0000%	$265	$245	$20
08 - Oil Spill Clean-up/Response Equipment	General	$330	96.9124%	$320	$295	$25
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$124,488	94.1569%	$117,214	$108,198	$9,016
08 - Oil Spill Clean-up/Response Equipment	Peaking	$70,184	95.0455%	$66,706	$61,575	$5,131
10 - Relocate Storm Water Runoff	Base	$6,215	95.7922%	$5,953	$5,495	$458
12 - Scherer Discharge Pipeline	Base	$33,749	95.7922%	$32,329	$29,842	$2,487
20 - Wastewater Discharge Elimination & Reuse	Peaking	$42,408	95.0455%	$40,307	$37,207	$3,101
21 - St. Lucie Turtle Nets	Base	$734,751	95.7922%	$703,834	$649,693	$54,141
22 - Pipeline Integrity Management	Intermediate	$141,109	94.1569%	$132,864	$122,644	$10,220
22 - Pipeline Integrity Management	Peaking	$122,293	95.0455%	$116,234	$107,293	$8,941
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$339,502	95.7922%	$325,217	$300,200	$25,017
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$265,847	100.0000%	$265,847	$245,397	$20,450
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$10,814	96.9124%	$10,480	$9,674	$806
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$695,260	94.1569%	$654,635	$604,279	$50,357
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$540,754	95.0455%	$513,962	$474,426	$39,536
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$369,721	89.9387%	$332,522	$306,943	$25,579
24 - Manatee Plant Reburn	Peaking	$2,979,301	95.1325%	$2,834,282	$0	$2,834,282
26 - UST Remove/Replacement	General	$6,651	96.9124%	$6,446	$5,950	$496
28 - CWA 316(b) Phase II Rule	Intermediate	$77,810	94.1569%	$73,264	$67,628	$5,636
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$36,219,119	95.7922%	$34,695,101	$32,026,247	$2,668,854
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$103	100.0000%	$103	$95	$8
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$113,401	94.1569%	$106,775	$98,561	$8,213
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$8,811,455	95.0455%	$8,374,890	$7,730,668	$644,222
33 - MATS Project	Base	$9,423,322	95.7922%	$9,026,810	$8,332,440	$694,370
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$354,911	95.7922%	$339,977	$313,825	$26,152
35 - Martin Plant Drinking Water System Compliance	Intermediate	$11,507	94.1569%	$10,835	$10,001	$833
35 - Martin Plant Drinking Water System Compliance	Peaking	$8,681	95.0455%	$8,251	$7,616	$635
36 - Low-Level Radioactive Waste Storage	Base	$1,653,138	95.7922%	$1,583,578	$1,461,764	$121,814
37 - DeSoto Next Generation Solar Energy Center	Solar	$11,943,760	95.7922%	$11,441,194	$10,561,102	$880,092
38 - Space Coast Next Generation Solar Energy Center	Solar	$5,561,296	95.7922%	$5,327,289	$4,917,498	$409,791
39 - Martin Next Generation Solar Energy Center	Intermediate	$34,080,447	94.1569%	$32,089,075	$29,620,685	$2,468,390
41 - Manatee Temporary Heating System	Distribution	$18,161	100.0000%	$18,161	$16,764	$1,397
41 - Manatee Temporary Heating System	Intermediate	$2,792,055	94.1569%	$2,628,911	$2,426,687	$202,224
41 - Manatee Temporary Heating System	Peaking	$528,245	95.0455%	$502,073	$463,452	$38,621
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$5,107,831	95.7922%	$4,892,905	$4,516,528	$376,377
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$950,223	94.1569%	$894,700	$825,877	$68,823
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$8,325	94.1569%	$7,839	$7,839	$0
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$6,280	95.0455%	$5,969	$5,969	$0
45 - 800 MW Unit ESP	Intermediate	$8,436	94.1569%	$7,943	$7,943	$0
45 - 800 MW Unit ESP	Peaking	$18,813,313	95.0455%	$17,881,205	$17,881,205	$0
47 - NPDES Permit Renewal Requirements	Base	$53,039	95.7922%	$50,807	$50,807	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$99,788	95.7922%	$95,589	$88,236	$7,353
54 - Coal Combustion Residuals	Base	$9,951,398	95.7922%	$9,532,666	$8,799,384	$733,282
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($17)	95.8799%	($17)	$0	($17)
	Total	$155,266,324		$147,843,295	$134,776,648	$13,066,647

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

FORM: 42-7E-2

JANUARY 2020 THROUGH DECEMBER 2020

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
2. Total of Capital Investment Projects	$12,990,460	$12,975,480	$12,968,667	$12,960,359	$12,961,467	$12,996,465	$12,929,421	$12,916,426	$12,906,620	$12,894,626	$12,875,549	$12,890,784	$155,266,324
3. Recoverable Costs Jurisdictionalized on Energy - Base	$2,348	$2,340	$2,332	$2,324	$2,316	$2,308	$2,293	$2,285	$2,277	$2,269	$2,261	$2,253	$27,607
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$23,271	$23,203	$23,134	$23,065	$22,997	$22,930	$22,777	$22,710	$22,643	$22,576	$22,508	$22,415	$274,230
Recoverable Costs Jurisdictionalized on Energy - Peaking	$272,317	$271,402	$270,488	$269,573	$268,659	$267,745	$265,969	$265,060	$264,152	$263,244	$262,335	$261,427	$3,202,370
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$31,134	$31,088	$31,047	$31,002	$30,958	$30,914	$30,699	$30,664	$30,620	$30,576	$30,532	$30,488	$369,721
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$5,337,494	$5,337,950	$5,347,133	$5,356,467	$5,312,849	$5,302,669	$5,315,966	$5,319,896	$5,327,905	$5,332,369	$5,329,155	$5,360,242	$63,980,095
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$3,159,903	$3,154,442	$3,148,529	$3,142,105	$3,312,089	$3,381,067	$3,338,452	$3,330,766	$3,323,633	$3,317,767	$3,312,161	$3,306,555	$39,227,469
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$2,587,060	$2,582,891	$2,578,461	$2,573,071	$2,453,817	$2,435,789	$2,419,659	$2,414,989	$2,410,281	$2,405,573	$2,401,047	$2,396,501	$29,659,138
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$1,492,660	$1,487,964	$1,483,418	$1,478,708	$1,473,806	$1,469,051	$1,448,599	$1,443,656	$1,438,814	$1,434,063	$1,429,441	$1,424,876	$17,505,056
Recoverable Costs Jurisdicitionalized on 12 CP Demand - General	$60,446	$60,404	$60,364	$60,314	$60,265	$60,217	$61,303	$62,730	$62,660	$62,589	$62,519	$62,449	$736,260
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$23,828	$23,795	$23,762	$23,728	$23,710	$23,777	$23,704	$23,669	$23,635	$23,601	$23,590	$23,579	$284,376
5. Retail Production Energy Jurisdictional Factor - Base	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	95.87989%	
Retail Production Energy Jurisdictional Factor - Intermediate	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	94.24302%	
Retail Production Energy Jurisdictional Factor - Peaking	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	95.13247%	
6. Retail Transmission Demand Jurisdictional Factor	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	
Retail Production Demand Jurisdictional Factor - Base	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	
Retail Production Demand Jurisdictional Factor - Intermediate	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	
Retail Production Demand Jurisdictional Factor - Peaking	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	
Retail Production Demand Jurisdictional Factor - Solar	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	
Retail Production Demand Jurisdictional Factor - General	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	
Retail Distribution Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7 .Jurisdictional Recoverable Costs - Transmission	$28,001	$27,960	$27,923	$27,883	$27,843	$27,803	$27,610	$27,579	$27,539	$27,500	$27,460	$27,420	$332,522
Jurisdictional Recoverable Costs - Production - Base	$5,115,156	$5,115,584	$5,124,374	$5,133,308	$5,091,517	$5,081,758	$5,094,481	$5,098,238	$5,105,903	$5,110,171	$5,107,084	$5,136,855	$61,314,428
Jurisdictional Recoverable Costs - Production - Intermediate	$2,997,196	$2,991,991	$2,986,358	$2,980,244	$3,140,232	$3,205,116	$3,164,847	$3,157,548	$3,150,768	$3,145,181	$3,139,839	$3,134,472	$37,193,792
Jurisdictional Recoverable Costs - Production - Peaking	$2,717,945	$2,713,113	$2,708,033	$2,702,039	$2,587,825	$2,569,819	$2,552,799	$2,547,496	$2,542,157	$2,536,818	$2,531,653	$2,526,468	$31,236,166
Jurisdictional Recoverable Costs - Production - Solar	$1,429,852	$1,425,354	$1,420,999	$1,416,488	$1,411,791	$1,407,237	$1,387,645	$1,382,910	$1,378,272	$1,373,721	$1,369,293	$1,364,921	$16,768,483
Jurisdictional Recoverable Costs - General	$58,579	$58,539	$58,500	$58,452	$58,405	$58,357	$59,411	$60,793	$60,725	$60,657	$60,589	$60,520	$713,527
Jurisdictional Recoverable Costs - Distribution	$23,828	$23,795	$23,762	$23,728	$23,710	$23,777	$23,704	$23,669	$23,635	$23,601	$23,590	$23,579	$284,376
8. Total Jurisdictional Recoverable Costs for Capital Investment Activities	$12,370,558	$12,356,337	$12,349,948	$12,342,143	$12,341,323	$12,373,866	$12,310,497	$12,298,233	$12,288,999	$12,277,648	$12,259,508	$12,274,236	$147,843,295

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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03 - Continuous Emission Monitoring Systems														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4,473)	($4,473)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4,473)	($4,473)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,290,617	$2,290,617	$2,290,617	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,290,167	$2,295,694	
3a. Less: Accumulated Depreciation	$521,499	$529,234	$536,970	$544,706	$552,442	$560,178	$567,914	$575,650	$583,386	$591,122	$598,858	$606,594	$609,830	
3b. Less: Capital Recovery Unamortized Balance	($203,055)	($200,638)	($198,221)	($195,803)	($193,386)	($190,969)	($188,552)	($186,134)	($183,717)	($181,300)	($178,882)	($176,465)	($174,048)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,972,174	$1,962,021	$1,951,868	$1,941,264	$1,931,111	$1,920,957	$1,910,804	$1,900,651	$1,890,498	$1,880,344	$1,870,191	$1,860,038	$1,849,911	
6. Average Net Investment		$1,967,097	$1,956,944	$1,946,566	$1,936,187	$1,926,034	$1,915,881	$1,905,728	$1,895,574	$1,885,421	$1,875,268	$1,865,115	$1,854,975	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$10,904	$10,847	$10,790	$10,732	$10,676	$10,620	$10,474	$10,418	$10,363	$10,307	$10,251	$10,195	$126,578
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,214	$2,203	$2,191	$2,179	$2,168	$2,157	$2,150	$2,139	$2,127	$2,116	$2,104	$2,093	$25,840
8. Investment Expenses														
a. Depreciation (e)		$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,709	$92,804
b. Amortization (f)		$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$29,008
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$23,271	$23,203	$23,134	$23,065	$22,997	$22,930	$22,777	$22,710	$22,643	$22,576	$22,508	$22,415	$274,230

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
General														
1. Investments														
a. Expenditures/Additions		$292	$2,520	$517	$0	$585	$0	$0	$0	$0	$0	$0	$0	$3,915
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$2,386,827	$0	$0	$0	$0	$0	$2,386,827
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$5,837,840	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	
3a. Less: Accumulated Depreciation	$472,135	$479,433	$486,730	$494,027	$501,325	$508,622	$515,919	$524,708	$534,989	$545,270	$555,551	$565,831	$576,112	
4. CWIP Non-Interest Bearing	$2,382,912	$2,383,205	$2,385,725	$2,386,242	$2,386,242	$2,386,827	$2,386,827	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,748,617	$7,741,612	$7,736,835	$7,730,055	$7,722,757	$7,716,045	$7,708,748	$7,699,959	$7,689,678	$7,679,397	$7,669,116	$7,658,835	$7,648,554	
6. Average Net Investment		$7,745,114	$7,739,223	$7,733,445	$7,726,406	$7,719,401	$7,712,396	$7,704,353	$7,694,818	$7,684,537	$7,674,256	$7,663,976	$7,653,695	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$42,932	$42,899	$42,867	$42,828	$42,789	$42,750	$42,344	$42,292	$42,235	$42,179	$42,122	$42,066	$510,304
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$8,718	$8,711	$8,705	$8,697	$8,689	$8,681	$8,692	$8,681	$8,670	$8,658	$8,646	$8,635	$104,183
8. Investment Expenses														
a. Depreciation (e)		$7,297	$7,297	$7,297	$7,297	$7,297	$7,297	$8,789	$10,281	$10,281	$10,281	$10,281	$10,281	$103,977
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$58,947	$58,908	$58,869	$58,822	$58,775	$58,729	$59,825	$61,254	$61,186	$61,118	$61,050	$60,982	$718,464

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	
3a. Less: Accumulated Depreciation	$1,046,857	$1,052,825	$1,058,792	$1,064,759	$1,070,726	$1,076,693	$1,082,660	$1,088,627	$1,094,594	$1,100,561	$1,106,528	$1,112,496	$1,118,463	
3b. Less: Capital Recovery Unamortized Balance	($259,817)	($256,716)	($253,615)	($250,514)	($247,413)	($244,312)	($241,211)	($238,110)	($235,009)	($231,908)	($228,807)	($225,706)	($222,605)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,503,592	$1,494,524	$1,485,456	$1,476,388	$1,467,319	$1,458,251	$1,449,183	$1,440,115	$1,431,047	$1,421,979	$1,412,911	$1,403,843	$1,394,775	
6. Average Net Investment		$1,499,058	$1,489,990	$1,480,922	$1,471,854	$1,462,785	$1,453,717	$1,444,649	$1,435,581	$1,426,513	$1,417,445	$1,408,377	$1,399,309	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$8,309	$8,259	$8,209	$8,159	$8,108	$8,058	$7,940	$7,890	$7,840	$7,791	$7,741	$7,691	$95,995
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,687	$1,677	$1,667	$1,657	$1,647	$1,636	$1,630	$1,620	$1,609	$1,599	$1,589	$1,579	$19,597
8. Investment Expenses														
a. Depreciation (e)		$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$71,605
b. Amortization (f)		$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$37,212
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$19,065	$19,004	$18,944	$18,883	$18,823	$18,762	$18,638	$18,578	$18,518	$18,458	$18,398	$18,338	$224,408

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	
3a. Less: Accumulated Depreciation	$1,461,603	$1,472,778	$1,483,953	$1,495,129	$1,506,304	$1,517,480	$1,528,655	$1,539,831	$1,551,006	$1,562,181	$1,573,357	$1,584,532	$1,595,708	
3b. Less: Capital Recovery Unamortized Balance	($1,949,792)	($1,926,589)	($1,903,387)	($1,880,184)	($1,856,981)	($1,833,778)	($1,810,575)	($1,787,373)	($1,764,170)	($1,740,967)	($1,717,764)	($1,694,561)	($1,671,358)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,004,740	$3,970,362	$3,935,984	$3,901,605	$3,867,227	$3,832,849	$3,798,471	$3,764,092	$3,729,714	$3,695,336	$3,660,958	$3,626,579	$3,592,201	
6. Average Net Investment		$3,987,551	$3,953,173	$3,918,794	$3,884,416	$3,850,038	$3,815,660	$3,781,281	$3,746,903	$3,712,525	$3,678,147	$3,643,768	$3,609,390	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$22,103	$21,913	$21,722	$21,532	$21,341	$21,150	$20,783	$20,594	$20,405	$20,216	$20,027	$19,838	$251,622
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$4,488	$4,450	$4,411	$4,372	$4,334	$4,295	$4,266	$4,227	$4,188	$4,150	$4,111	$4,072	$51,364
8. Investment Expenses														
a. Depreciation (e)		$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$134,105
b. Amortization (f)		$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$278,434
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$60,970	$60,741	$60,511	$60,282	$60,053	$59,824	$59,427	$59,199	$58,971	$58,744	$58,516	$58,288	$715,525

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
Intermediate														
1. Investments														
a. Expenditures/Additions		$318,963	$3,773	$974	$0	$4,088	$0	$0	$0	$0	$0	$20,879	$0	$348,677
b. Clearings to Plant		($21,141)	$0	$0	$0	$0	$0	$0	$0	$0	$405,369	$20,879	$0	$405,107
c. Retirements		($21,141)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($21,141)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$515,580	$494,439	$494,439	$494,439	$494,439	$494,439	$494,439	$494,439	$494,439	$494,439	$899,808	$920,687	$920,687	
3a. Less: Accumulated Depreciation	$8,720	($7,938)	($3,581)	$776	$5,132	$9,489	$13,846	$18,203	$22,560	$26,917	$31,670	$36,991	$42,486	
3b. Less: Capital Recovery Unamortized Balance	$154	$152	$150	$148	$146	$145	$143	$141	$139	$137	$135	$134	$132	
4. CWIP Non-Interest Bearing	$77,572	$396,534	$400,308	$401,282	$401,282	$405,369	$405,369	$405,369	$405,369	$405,369	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$584,278	$898,760	$898,178	$894,797	$890,441	$890,174	$885,819	$881,464	$877,108	$872,753	$868,003	$883,562	$878,069	
6. Average Net Investment		$741,519	$898,469	$896,487	$892,619	$890,308	$887,996	$883,641	$879,286	$874,931	$870,378	$875,783	$880,816	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$4,110	$4,980	$4,969	$4,948	$4,935	$4,922	$4,857	$4,833	$4,809	$4,784	$4,813	$4,841	$57,801
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$835	$1,011	$1,009	$1,005	$1,002	$1,000	$997	$992	$987	$982	$988	$994	$11,801
8. Investment Expenses														
a. Depreciation (e)		$4,483	$4,357	$4,357	$4,357	$4,357	$4,357	$4,357	$4,357	$4,357	$4,752	$5,321	$5,495	$54,908
b. Amortization (f)		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($22)
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$9,426	$10,347	$10,334	$10,308	$10,292	$10,277	$10,209	$10,180	$10,151	$10,516	$11,121	$11,328	$124,488

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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FORM: 42-8E

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$2,555	$0	$0	$0	$0	$0	$0	$0	$0	$15,751	$0	$18,306
b. Clearings to Plant		($15,948)	$0	$0	$0	$0	$0	$52,481	$0	$0	$0	$15,751	($3,374)	$48,910
c. Retirements		($15,948)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,374)	($19,322)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$454,472	$438,523	$438,523	$438,523	$438,523	$438,523	$438,523	$491,005	$491,005	$491,005	$491,005	$506,756	$503,382	
3a. Less: Accumulated Depreciation	$132,037	$119,593	$123,002	$126,411	$129,820	$133,229	$136,638	$140,085	$143,570	$147,055	$150,541	$154,157	$154,511	
4. CWIP Non-Interest Bearing	$49,927	$49,927	$52,481	$52,481	$52,481	$52,481	$52,481	($0)	($0)	($0)	($0)	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$372,361	$368,857	$368,003	$364,594	$361,185	$357,776	$354,367	$350,920	$347,435	$343,949	$340,464	$352,599	$348,871	
6. Average Net Investment		$370,609	$368,430	$366,298	$362,889	$359,480	$356,071	$352,643	$349,177	$345,692	$342,207	$346,532	$350,735	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$2,054	$2,042	$2,030	$2,012	$1,993	$1,974	$1,938	$1,919	$1,900	$1,881	$1,905	$1,928	$23,575
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$417	$415	$412	$408	$405	$401	$398	$394	$390	$386	$391	$396	$4,813
8. Investment Expenses														
a. Depreciation (e)		$3,504	$3,409	$3,409	$3,409	$3,409	$3,409	$3,447	$3,485	$3,485	$3,485	$3,616	$3,728	$41,796
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$5,975	$5,866	$5,852	$5,829	$5,806	$5,784	$5,783	$5,798	$5,775	$5,752	$5,912	$6,051	$70,184

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	($20,503)	$0	$0	$0	$0	$0	$0	$0	($20,503)
b. Clearings to Plant		$0	$0	$0	$0	$20,503	$117,075	$0	$0	$0	$0	$32,505	$0	$170,083
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,406,962	$3,406,962	$3,406,962	$3,406,962	$3,406,962	$3,427,465	$3,544,540	$3,544,540	$3,544,540	$3,544,540	$3,544,540	$3,577,045	$3,577,045	
3a. Less: Accumulated Depreciation	$981,017	$986,000	$990,983	$995,967	$1,000,950	$1,005,948	$1,011,046	$1,016,230	$1,021,414	$1,026,598	$1,031,781	$1,036,989	$1,042,220	
4. CWIP Non-Interest Bearing	$170,083	$170,083	$170,083	$170,083	$170,083	$149,580	$32,505	$32,505	$32,505	$32,505	$32,505	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,596,028	$2,591,045	$2,586,062	$2,581,078	$2,576,095	$2,571,097	$2,565,999	$2,560,815	$2,555,631	$2,550,447	$2,545,264	$2,540,056	$2,534,825	
6. Average Net Investment		$2,593,536	$2,588,553	$2,583,570	$2,578,587	$2,573,596	$2,568,548	$2,563,407	$2,558,223	$2,553,039	$2,547,855	$2,542,660	$2,537,440	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$14,376	$14,349	$14,321	$14,293	$14,266	$14,238	$14,089	$14,060	$14,032	$14,003	$13,975	$13,946	$169,948
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,919	$2,914	$2,908	$2,902	$2,897	$2,891	$2,892	$2,886	$2,880	$2,874	$2,869	$2,863	$34,696
8. Investment Expenses														
a. Depreciation (e)		$4,983	$4,983	$4,983	$4,983	$4,998	$5,098	$5,184	$5,184	$5,184	$5,184	$5,208	$5,231	$61,203
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$22,279	$22,245	$22,212	$22,179	$22,161	$22,227	$22,165	$22,130	$22,096	$22,062	$22,051	$22,040	$265,847

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

FORM: 42-8E

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	($286,434)	$0	$0	$0	$2,530	$41,991	$195,285	$229,941	$333,906	$125,975	$0	$643,194
b. Clearings to Plant		$0	$286,434	$0	$0	$0	$0	$0	$0	$0	$425,728	$0	$556,688	$1,268,849
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,983,517	$4,983,517	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,269,951	$5,695,678	$5,695,678	$6,252,366	
3a. Less: Accumulated Depreciation	$770,353	$782,234	$794,461	$807,035	$819,609	$832,182	$844,756	$857,330	$869,903	$882,477	$895,466	$908,869	$922,793	
3b. Less: Capital Recovery Unamortized Balance	($888,453)	($877,839)	($867,224)	($856,610)	($845,995)	($835,381)	($824,767)	($814,152)	($803,538)	($792,924)	($782,309)	($771,695)	($761,081)	
4. CWIP Non-Interest Bearing	$0	$0	($286,434)	($286,434)	($286,434)	($286,434)	($283,904)	($241,913)	($46,628)	$183,313	$91,491	$217,466	($339,221)	
5. Net Investment (Lines 2 - 3 + 4)	$5,101,617	$5,079,121	$5,056,279	$5,033,091	$5,009,903	$4,986,715	$4,966,057	$4,984,860	$5,156,957	$5,363,710	$5,674,013	$5,775,970	$5,751,432	
6. Average Net Investment		$5,090,369	$5,067,700	$5,044,685	$5,021,497	$4,998,309	$4,976,386	$4,975,458	$5,070,909	$5,260,334	$5,518,862	$5,724,992	$5,763,701	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$28,216	$28,091	$27,963	$27,834	$27,706	$27,584	$27,346	$27,871	$28,912	$30,333	$31,465	$31,678	$344,999
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$5,730	$5,704	$5,678	$5,652	$5,626	$5,601	$5,613	$5,721	$5,935	$6,226	$6,459	$6,503	$70,449
8. Investment Expenses														
a. Depreciation (e)		$11,881	$12,228	$12,574	$12,574	$12,574	$12,574	$12,574	$12,574	$12,574	$12,989	$13,404	$13,923	$152,440
b. Amortization (f)		$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$127,372
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$56,442	$56,637	$56,829	$56,675	$56,520	$56,374	$56,147	$56,780	$58,034	$60,162	$61,943	$62,719	$695,260

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Peaking														
1. Investments														
a. Expenditures/Additions		$57,253	$0	$5,255	$0	$0	$0	$0	$0	$0	$0	$0	$0	$62,508
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	
3a. Less: Accumulated Depreciation	$1,305,659	$1,317,361	$1,329,063	$1,340,765	$1,352,467	$1,364,169	$1,375,871	$1,387,573	$1,399,275	$1,410,977	$1,422,679	$1,434,381	$1,446,083	
3b. Less: Capital Recovery Unamortized Balance	($1,097,801)	($1,084,770)	($1,071,738)	($1,058,706)	($1,045,675)	($1,032,643)	($1,019,612)	($1,006,580)	($993,549)	($980,517)	($967,486)	($954,454)	($941,423)	
4. CWIP Non-Interest Bearing	$276,713	$333,967	$333,967	$339,221	$339,221	$339,221	$339,221	$339,221	$339,221	$339,221	$339,221	$339,221	$339,221	
5. Net Investment (Lines 2 - 3 + 4)	$3,147,787	$3,180,307	$3,155,574	$3,136,095	$3,111,362	$3,086,628	$3,061,895	$3,037,161	$3,012,428	$2,987,694	$2,962,961	$2,938,227	$2,913,494	
6. Average Net Investment		$3,164,047	$3,167,940	$3,145,834	$3,123,728	$3,098,995	$3,074,261	$3,049,528	$3,024,794	$3,000,061	$2,975,327	$2,950,594	$2,925,861	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$17,538	$17,560	$17,438	$17,315	$17,178	$17,041	$16,761	$16,625	$16,489	$16,353	$16,217	$16,081	$202,595
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3,561	$3,566	$3,541	$3,516	$3,488	$3,460	$3,440	$3,413	$3,385	$3,357	$3,329	$3,301	$41,357
8. Investment Expenses														
a. Depreciation (e)		$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$140,423
b. Amortization (f)		$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$156,378
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$45,833	$45,859	$45,712	$45,565	$45,400	$45,235	$44,935	$44,771	$44,607	$44,443	$44,279	$44,115	$540,754

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Transmission														
1. Investments														
a. Expenditures/Additions		($1,413)	$1,413	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	($297)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($297)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,118,429	$4,118,429	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	
3a. Less: Accumulated Depreciation	$445,391	$452,058	$458,724	$465,389	$472,055	$478,721	$485,387	$492,043	$498,709	$505,374	$512,040	$518,706	$525,372	
4. CWIP Non-Interest Bearing	$0	($1,413)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,673,038	$3,664,958	$3,659,409	$3,652,743	$3,646,077	$3,639,411	$3,632,746	$3,626,090	$3,619,424	$3,612,758	$3,606,092	$3,599,426	$3,592,761	
6. Average Net Investment		$3,668,998	$3,662,184	$3,656,076	$3,649,410	$3,642,744	$3,636,079	$3,629,418	$3,622,757	$3,616,091	$3,609,425	$3,602,759	$3,596,094	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$20,337	$20,300	$20,266	$20,229	$20,192	$20,155	$19,948	$19,911	$19,875	$19,838	$19,801	$19,765	$240,617
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$4,130	$4,122	$4,115	$4,108	$4,100	$4,093	$4,095	$4,087	$4,080	$4,072	$4,065	$4,057	$49,124
8. Investment Expenses														
a. Depreciation (e)		$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,656	$6,666	$6,666	$6,666	$6,666	$6,666	$79,981
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$31,134	$31,088	$31,047	$31,002	$30,958	$30,914	$30,699	$30,664	$30,620	$30,576	$30,532	$30,488	$369,721

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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FORM: 42-8E

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
24 - Manatee Reburn														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	
3a. Less: Accumulated Depreciation	$12,957,135	$13,084,831	$13,212,527	$13,340,223	$13,467,920	$13,595,616	$13,723,312	$13,851,008	$13,978,704	$14,106,401	$14,234,097	$14,361,793	$14,489,489	
4. CWIP Non-Interest Bearing	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$18,906,584	$18,778,888	$18,651,191	$18,523,495	$18,395,799	$18,268,103	$18,140,407	$18,012,710	$17,885,014	$17,757,318	$17,629,622	$17,501,926	$17,374,229	
6. Average Net Investment		$18,842,736	$18,715,039	$18,587,343	$18,459,647	$18,331,951	$18,204,255	$18,076,558	$17,948,862	$17,821,166	$17,693,470	$17,565,774	$17,438,077	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$104,446	$103,739	$103,031	$102,323	$101,615	$100,907	$99,352	$98,650	$97,948	$97,246	$96,544	$95,842	$1,201,643
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$21,209	$21,066	$20,922	$20,778	$20,634	$20,491	$20,394	$20,250	$20,106	$19,962	$19,818	$19,674	$245,303
8. Investment Expenses														
a. Depreciation (e)		$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$1,532,354
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$253,352	$252,500	$251,649	$250,797	$249,946	$249,094	$247,442	$246,596	$245,750	$244,904	$244,058	$243,212	$2,979,301

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$1,637,989	$159,296	$255,297	$109,413	$0	$0	$0	$0	$0	$2,161,995
b. Clearings to Plant		($0)	$92,532	$1,076,639	($1,169,171)	$0	$0	($268)	$0	$0	$0	$0	$1,797,285	$1,797,016
c. Retirements		$0	$0	$0	$0	$0	$0	($268)	$0	$0	$0	$0	$0	($268)
d. Other (a)		$0	$0	$0	$0	($43,439,531)	$0	$0	$0	$0	$0	$0	$0	($43,439,531)
2. Plant-In-Service/Depreciation Base (b)	$359,943,378	$359,943,378	$360,035,910	$361,112,549	$359,943,378	$359,943,378	$359,943,378	$359,943,110	$359,943,110	$359,943,110	$359,943,110	$359,943,110	$361,740,394	
3a. Less: Accumulated Depreciation	$65,990,209	$66,787,065	$67,584,011	$68,382,087	$69,180,073	$69,976,929	$70,773,786	$71,570,372	$72,367,225	$73,164,078	$73,960,931	$74,757,784	$75,556,375	
3b. Less: Capital Recovery Unamortized Balance	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$1,637,989	$1,797,285	$2,052,582	$2,161,995	$2,161,995	$2,161,995	$2,161,995	$2,161,995	$364,710	
5. Net Investment (Lines 2 - 3 + 4)	$337,392,700	$336,595,843	$335,891,430	$336,169,993	$335,840,824	$335,203,264	$334,661,704	$333,974,263	$333,177,410	$332,380,557	$331,583,704	$330,786,851	$329,988,260	
6. Average Net Investment		$336,994,272	$336,243,637	$336,030,711	$336,005,409	$335,522,044	$334,932,484	$334,317,984	$333,575,836	$332,778,983	$331,982,130	$331,185,277	$330,387,555	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,867,979	$1,863,818	$1,862,638	$1,862,498	$1,859,818	$1,856,550	$1,837,464	$1,833,385	$1,829,006	$1,824,626	$1,820,247	$1,815,862	$22,133,893
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$379,321	$378,476	$378,236	$378,208	$377,664	$377,000	$377,178	$376,340	$375,441	$374,542	$373,643	$372,743	$4,518,792
8. Investment Expenses														
a. Depreciation (e)		$796,856	$796,946	$798,076	$797,986	$796,856	$796,856	$796,855	$796,853	$796,853	$796,853	$796,853	$798,590	$9,566,434
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$3,044,156	$3,039,240	$3,038,950	$3,038,692	$3,034,338	$3,030,407	$3,011,497	$3,006,579	$3,001,300	$2,996,022	$2,990,743	$2,987,196	$36,219,119

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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34 - St Lucie Cooling Water System Inspection & Maintenance														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)														
3a. Less: Accumulated Depreciation														
4. CWIP Non-Interest Bearing	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	
5. Net Investment (Lines 2 - 3 + 4)	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	
6. Average Net Investment		$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$24,666	$24,666	$24,666	$24,666	$24,666	$24,666	$24,457	$24,457	$24,457	$24,457	$24,457	$24,457	$294,737
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,020	$5,020	$5,020	$5,020	$5,020	$5,020	$60,174
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$29,675	$29,675	$29,675	$29,675	$29,675	$29,675	$29,477	$29,477	$29,477	$29,477	$29,477	$29,477	$354,911

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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35 - Martin Plant Drinking Water System Compliance														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	
3a. Less: Accumulated Depreciation	$30,605	$30,887	$31,169	$31,451	$31,732	$32,014	$32,296	$32,578	$32,859	$33,141	$33,423	$33,705	$33,986	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$103,568	$103,286	$103,004	$102,722	$102,440	$102,159	$101,877	$101,595	$101,313	$101,032	$100,750	$100,468	$100,186	
6. Average Net Investment		$103,427	$103,145	$102,863	$102,581	$102,300	$102,018	$101,736	$101,454	$101,173	$100,891	$100,609	$100,327	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$573	$572	$570	$569	$567	$565	$559	$558	$556	$555	$553	$551	$6,748
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$116	$116	$116	$115	$115	$115	$115	$114	$114	$114	$114	$113	$1,378
8. Investment Expenses														
a. Depreciation (e)		$282	$282	$282	$282	$282	$282	$282	$282	$282	$282	$282	$282	$3,381
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$971	$970	$968	$966	$964	$962	$956	$954	$952	$950	$948	$946	$11,507

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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35 - Martin Plant Drinking Water System Compliance														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	
3a. Less: Accumulated Depreciation	$23,088	$23,301	$23,513	$23,726	$23,938	$24,151	$24,364	$24,576	$24,789	$25,001	$25,214	$25,426	$25,639	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$78,130	$77,917	$77,705	$77,492	$77,280	$77,067	$76,855	$76,642	$76,429	$76,217	$76,004	$75,792	$75,579	
6. Average Net Investment		$78,024	$77,811	$77,598	$77,386	$77,173	$76,961	$76,748	$76,536	$76,323	$76,111	$75,898	$75,685	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$432	$431	$430	$429	$428	$427	$422	$421	$419	$418	$417	$416	$5,091
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$88	$88	$87	$87	$87	$87	$87	$86	$86	$86	$86	$85	$1,039
8. Investment Expenses														
a. Depreciation (e)		$213	$213	$213	$213	$213	$213	$213	$213	$213	$213	$213	$213	$2,551
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$733	$731	$730	$729	$727	$726	$721	$720	$718	$717	$715	$714	$8,681

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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37 - DeSoto Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$1,062	$1,208	$5,083	$47	$0	$0	$0	$2,016	$2,016	$1,008	$0	$12,440
b. Clearings to Plant		($1,886)	($1,454)	$9,909	($32,614)	($5,129)	($5,547)	($17,386)	($4,150)	$0	($7,747)	$5,040	$0	($60,965)
c. Retirements		($1,886)	($1,454)	$0	($32,614)	($5,129)	($5,547)	($17,386)	($11,560)	$0	($7,747)	$0	$0	($83,324)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$153,561,354	$153,559,468	$153,558,013	$153,567,922	$153,535,308	$153,530,179	$153,524,632	$153,507,246	$153,503,096	$153,503,096	$153,495,349	$153,500,389	$153,500,389	
3a. Less: Accumulated Depreciation	$52,081,935	$52,525,767	$52,969,983	$53,415,717	$53,828,725	$54,268,953	$54,708,658	$55,136,346	$55,569,663	$56,014,488	$56,451,501	$56,896,203	$57,340,913	
4. CWIP Non-Interest Bearing	$10	$10	$1,072	$2,280	$7,363	$7,410	$7,410	$7,410	($0)	$2,016	$4,032	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$101,479,428	$101,033,711	$100,589,102	$100,154,485	$99,713,947	$99,268,637	$98,823,385	$98,378,310	$97,933,433	$97,490,625	$97,047,880	$96,604,185	$96,159,476	
6. Average Net Investment		$101,256,570	$100,811,406	$100,371,794	$99,934,216	$99,491,292	$99,046,011	$98,600,848	$98,155,872	$97,712,029	$97,269,252	$96,826,033	$96,381,831	
a. Average ITC Balance		$28,990,785	$28,868,719	$28,746,653	$28,624,587	$28,502,521	$28,380,455	$28,258,389	$28,136,323	$28,014,257	$27,892,191	$27,770,125	$27,648,059	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$611,952	$609,271	$606,621	$603,982	$601,314	$598,632	$585,104	$582,472	$579,846	$577,226	$574,604	$571,976	$7,103,002
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$121,471	$120,939	$120,412	$119,888	$119,358	$118,825	$118,380	$117,847	$117,315	$116,785	$116,254	$115,722	$1,423,196
8. Investment Expenses														
a. Depreciation (e)		$433,531	$433,484	$433,547	$433,435	$433,170	$433,065	$432,887	$432,690	$432,638	$432,573	$432,516	$432,523	$5,196,058
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$146,244
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($1,924,740)
9. Total System Recoverable Costs (Lines 7 & 8)		$1,018,746	$1,015,486	$1,012,372	$1,009,098	$1,005,634	$1,002,315	$988,163	$984,801	$981,591	$978,376	$975,165	$972,012	$11,943,760

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
38 - Space Coast Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$0	$1,110	($871)	$0	$0	$0	$0	$0	$0	$0	$0	$239
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($8,680)	($11,223)	($14,962)	$0	$0	$0	($34,865)
c. Retirements		$0	$0	$0	$0	$0	$0	($8,680)	($11,560)	($14,962)	$0	$0	$0	($35,202)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,591,411	$70,582,731	$70,571,508	$70,556,546	$70,556,546	$70,556,546	$70,556,546	
3a. Less: Accumulated Depreciation	$23,056,153	$23,256,037	$23,455,921	$23,655,805	$23,855,688	$24,055,572	$24,255,456	$24,446,587	$24,634,671	$24,819,134	$25,018,435	$25,217,735	$25,417,036	
4. CWIP Non-Interest Bearing	$98	$98	$98	$1,208	$337	$337	$337	$337	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$47,535,356	$47,335,472	$47,135,588	$46,936,815	$46,736,060	$46,536,176	$46,336,293	$46,136,482	$45,936,837	$45,737,412	$45,538,111	$45,338,810	$45,139,510	
6. Average Net Investment		$47,435,414	$47,235,530	$47,036,201	$46,836,437	$46,636,118	$46,436,234	$46,236,387	$46,036,659	$45,837,124	$45,637,761	$45,438,461	$45,239,160	
a. Average ITC Balance		$12,438,795	$12,387,606	$12,336,417	$12,285,228	$12,234,039	$12,182,850	$12,131,661	$12,080,472	$12,029,283	$11,978,094	$11,926,905	$11,875,716	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$284,683	$283,485	$282,291	$281,094	$279,894	$278,697	$272,660	$271,484	$270,309	$269,135	$267,961	$266,788	$3,308,479
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$56,610	$56,372	$56,134	$55,896	$55,657	$55,419	$55,228	$54,990	$54,752	$54,514	$54,276	$54,039	$663,888
8. Investment Expenses														
a. Depreciation (e)		$195,492	$195,492	$195,492	$195,492	$195,492	$195,491	$195,419	$195,252	$195,033	$194,909	$194,909	$194,909	$2,343,381
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$52,704
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($807,156)
9. Total System Recoverable Costs (Lines 7 & 8)		$473,913	$472,478	$471,046	$469,611	$468,172	$466,736	$460,436	$458,855	$457,223	$455,687	$454,275	$452,864	$5,561,296

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
39 - Martin Next Generation Solar Energy Center														
Intermediate														
1. Investments														
a. Expenditures/Additions		($1,781,021)	$71,071	$403,010	$129,180	$28,970	$151,170	$154,193	$151,170	$151,170	$151,170	$262,129	$151,170	$23,382
b. Clearings to Plant		$569,415	$61,820	$6,695	($95,126)	$95,461	$169,776	$47,979	$0	$0	$0	$0	$1,172,172	$2,028,192
c. Retirements		($1,335,220)	$0	$0	($95,126)	$0	$0	$0	$0	$0	$0	$0	$0	($1,430,346)
d. Other (a)		($22,956)	($9,668)	($50,264)	($24,333)	($24,724)	$0	$0	$0	$0	$0	$0	$0	($131,945)
2. Plant-In-Service/Depreciation Base (b)	$426,051,646	$426,621,061	$426,682,881	$426,822,005	$426,726,879	$426,822,340	$426,992,116	$427,040,095	$427,040,095	$427,040,095	$427,040,095	$427,040,095	$428,212,267	
3a. Less: Accumulated Depreciation	$114,083,425	$113,801,837	$114,869,514	$115,896,677	$116,854,539	$117,907,137	$118,984,777	$120,062,681	$121,140,644	$122,218,607	$123,296,571	$124,374,534	$125,453,904	
4. CWIP Non-Interest Bearing	$2,298,671	$517,650	$588,721	$991,730	$1,120,910	$1,149,881	$1,131,274	$1,237,489	$1,388,659	$1,539,829	$1,690,999	$1,953,128	$932,125	
5. Net Investment (Lines 2 - 3 + 4)	$314,266,891	$313,336,874	$312,402,088	$311,917,058	$310,993,250	$310,065,084	$309,138,613	$308,214,903	$307,288,110	$306,361,317	$305,434,523	$304,618,689	$303,690,489	
6. Average Net Investment		$313,801,882	$312,869,481	$312,159,573	$311,455,154	$310,529,167	$309,601,849	$308,676,758	$307,751,507	$306,824,713	$305,897,920	$305,026,606	$304,154,589	
a. Average ITC Balance		$86,221,201	$85,877,403	$85,533,605	$85,189,807	$84,846,009	$84,502,211	$84,158,413	$83,814,615	$83,470,817	$83,127,019	$82,783,221	$82,439,423	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,890,153	$1,884,384	$1,879,848	$1,875,342	$1,869,608	$1,863,867	$1,825,130	$1,819,519	$1,813,900	$1,808,281	$1,802,966	$1,797,648	$22,130,645
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$375,512	$374,374	$373,486	$372,604	$371,473	$370,340	$369,508	$368,377	$367,244	$366,112	$365,042	$363,971	$4,438,043
8. Investment Expenses														
a. Depreciation (e)		$1,027,033	$1,027,790	$1,027,872	$1,027,766	$1,027,767	$1,028,085	$1,028,349	$1,028,408	$1,028,408	$1,028,408	$1,028,408	$1,029,815	$12,338,110
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$594,660
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($5,421,012)
9. Total System Recoverable Costs (Lines 7 & 8)		$2,890,502	$2,884,352	$2,879,010	$2,873,516	$2,866,652	$2,860,096	$2,820,790	$2,814,108	$2,807,357	$2,800,605	$2,794,221	$2,789,239	$34,080,447

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
41 - Manatee Temporary Heating System														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$36,256	$28	$431	$79	$4,439,770	$0	$0	$0	$0	$0	$0	$0	$4,476,564
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$453,549	$0	$0	$0	$0	$0	$0	$0	$453,549
2. Plant-In-Service/Depreciation Base (b)	$13,096,633	$13,132,888	$13,132,917	$13,133,348	$13,133,427	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	
3a. Less: Accumulated Depreciation	$4,246,609	$4,341,827	$4,437,249	$4,532,673	$4,628,098	$5,277,965	$5,474,285	$5,670,605	$5,866,926	$6,063,246	$6,259,566	$6,455,886	$6,652,206	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$8,850,024	$8,791,062	$8,695,667	$8,600,675	$8,505,329	$12,295,232	$12,098,912	$11,902,591	$11,706,271	$11,509,951	$11,313,631	$11,117,311	$10,920,991	
6. Average Net Investment		$8,820,543	$8,743,364	$8,648,171	$8,553,002	$10,400,280	$12,197,072	$12,000,752	$11,804,431	$11,608,111	$11,411,791	$11,215,471	$11,019,151	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$48,893	$48,465	$47,937	$47,410	$57,649	$67,609	$65,958	$64,879	$63,800	$62,721	$61,642	$60,563	$697,526
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$9,928	$9,842	$9,734	$9,627	$11,707	$13,729	$13,539	$13,318	$13,096	$12,875	$12,653	$12,432	$142,480
8. Investment Expenses														
a. Depreciation (e)		$95,218	$95,423	$95,424	$95,425	$196,318	$196,320	$196,320	$196,320	$196,320	$196,320	$196,320	$196,320	$1,952,048
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$154,039	$153,729	$153,095	$152,462	$265,674	$277,658	$275,817	$274,517	$273,216	$271,916	$270,615	$269,315	$2,792,055

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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42 - Turkey Point Cooling Canal Monitoring Plan														
Base														
1. Investments														
a. Expenditures/Additions		$550,722	$350,772	$396,584	$1,096,833	($14,453,196)	$1,370,928	$874,486	$627,310	$380,000	$20,000	$20,000	$1,681,102	($7,084,460)
b. Clearings to Plant		$714,322	$0	$0	$0	$0	$0	$0	$377,717	$4,109,720	$0	$0	$0	$5,201,759
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$40,096,965	$40,811,287	$40,811,287	$40,811,287	$40,811,287	$40,811,287	$40,811,287	$40,811,287	$41,189,004	$45,298,724	$45,298,724	$45,298,724	$45,298,724	
3a. Less: Accumulated Depreciation	$3,321,476	$3,427,236	$3,534,089	$3,640,942	$3,747,794	$3,854,647	$3,961,500	$4,068,352	$4,175,698	$4,288,895	$4,407,453	$4,526,010	$4,644,567	
4. CWIP Non-Interest Bearing	$16,168,005	$16,718,726	$17,069,499	$17,466,083	$18,562,916	$4,109,720	$5,480,647	$6,355,133	$6,604,727	$2,875,007	$2,895,007	$2,915,007	$4,596,109	
5. Net Investment (Lines 2 - 3 + 4)	$52,943,494	$54,102,777	$54,346,697	$54,636,429	$55,626,409	$41,066,360	$42,330,435	$43,098,068	$43,618,033	$43,884,835	$43,786,278	$43,687,720	$45,250,265	
6. Average Net Investment		$53,523,136	$54,224,737	$54,491,563	$55,131,419	$48,346,384	$41,698,397	$42,714,252	$43,358,051	$43,751,434	$43,835,557	$43,736,999	$44,468,993	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$296,682	$300,571	$302,050	$305,597	$267,987	$231,137	$234,764	$238,303	$240,465	$240,927	$240,385	$244,409	$3,143,276
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$60,246	$61,035	$61,336	$62,056	$54,419	$46,936	$48,190	$48,917	$49,360	$49,455	$49,344	$50,170	$641,463
8. Investment Expenses														
a. Depreciation (e)		$105,760	$106,853	$106,853	$106,853	$106,853	$106,853	$106,853	$107,345	$113,198	$118,557	$118,557	$118,557	$1,323,092
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$462,688	$468,459	$470,238	$474,505	$429,258	$384,925	$389,807	$394,565	$403,023	$408,940	$408,287	$413,136	$5,107,831

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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42 - Turkey Point Cooling Canal Monitoring Plan														
Intermediate														
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant	$0	$0	$0	$0	$0	$14,859,266	$0	$0	$0	$0	$0	$0	$0	$14,859,266
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)						$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	
3a. Less: Accumulated Depreciation						$14,426	$43,278	$72,129	$100,981	$129,833	$158,685	$187,536	$216,388	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$14,844,840	$14,815,988	$14,787,136	$14,758,285	$14,729,433	$14,700,581	$14,671,729	$14,642,878	
6. Average Net Investment		$0	$0	$0	$0	$7,422,420	$14,830,414	$14,801,562	$14,772,711	$14,743,859	$14,715,007	$14,686,155	$14,657,304	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$0	$0	$0	$41,143	$82,206	$81,352	$81,193	$81,035	$80,876	$80,717	$80,559	$609,081
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$0	$0	$0	$0	$8,355	$16,693	$16,699	$16,667	$16,634	$16,601	$16,569	$16,536	$124,754
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$14,426	$28,852	$28,852	$28,852	$28,852	$28,852	$28,852	$28,852	$216,388
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$0	$0	$0	$0	$63,923	$127,751	$126,903	$126,711	$126,520	$126,329	$126,138	$125,947	$950,223

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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45 - 800 MW Unit ESP														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$404,851	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$404,851
c. Retirements		$0	$404,851	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$404,851
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$107,963,814	$107,963,814	$108,368,665	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	
3a. Less: Accumulated Depreciation	($65,627,065)	($65,197,468)	($64,362,179)	($63,930,791)	($63,499,404)	($63,068,016)	($62,636,628)	($62,205,241)	($61,773,853)	($61,342,466)	($60,911,078)	($60,479,690)	($60,048,303)	
4. CWIP Non-Interest Bearing	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	
5. Net Investment (Lines 2 - 3 + 4)	$173,590,500	$173,160,904	$172,730,466	$172,299,805	$171,868,418	$171,437,030	$171,005,643	$170,574,255	$170,142,867	$169,711,480	$169,280,092	$168,848,705	$168,417,317	
6. Average Net Investment		$173,375,702	$172,945,685	$172,515,135	$172,084,112	$171,652,724	$171,221,336	$170,789,949	$170,358,561	$169,927,174	$169,495,786	$169,064,398	$168,633,011	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$961,032	$958,648	$956,262	$953,872	$951,481	$949,090	$938,689	$936,318	$933,947	$931,576	$929,205	$926,834	$11,326,952
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$195,152	$194,668	$194,183	$193,698	$193,212	$192,727	$192,685	$192,199	$191,712	$191,225	$190,738	$190,252	$2,312,450
8. Investment Expenses														
a. Depreciation (e)		$429,597	$430,438	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$5,173,911
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$1,585,780	$1,583,754	$1,581,832	$1,578,958	$1,576,081	$1,573,204	$1,562,761	$1,559,904	$1,557,046	$1,554,188	$1,551,331	$1,548,473	$18,813,313

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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47 - NPDES Permit Renewal Requirements														
Base														
1. Investments														
a. Expenditures/Additions	0	$0	$0	$0	$0	$2,266	$80,000	$426,000	$426,000	$615,000	$123,000	$315,000	$315,000	$2,302,266
b. Clearings to Plant	0	$0	$0	$0	$0	$0	$0	$0	$0	$38,004	$0	$0	$0	$38,004
c. Retirements	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)										$38,004	$38,004	$38,004	$38,004	
3a. Less: Accumulated Depreciation										$114	$343	$572	$800	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$2,266	$82,266	$508,266	$934,266	$1,511,262	$1,634,262	$1,949,262	$2,264,262	
5. Net Investment (Lines 2 - 3 + 4)						$2,266	$82,266	$508,266	$934,266	$1,549,152	$1,671,923	$1,986,694	$2,301,466	
6. Average Net Investment						$1,133	$42,266	$295,266	$721,266	$1,241,709	$1,610,537	$1,829,309	$2,144,080	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$0	$0	$0	$6	$234	$1,623	$3,964	$6,825	$8,852	$10,054	$11,784	$43,342
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$0	$0	$0	$0	$1	$48	$333	$814	$1,401	$1,817	$2,064	$2,419	$8,896
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$114	$229	$229	$229	$800
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$0	$0	$0	$0	$8	$282	$1,956	$4,778	$8,340	$10,897	$12,347	$14,432	$53,039

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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FORM: 42-8E

JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
50 - Steam Electric Effluent Guidelines Revised Rules														
Base														
1. Investments														
a. Expenditures/Additions	$0	$0	$30,395	$32,458	$81,005	$66,088	$48,103	$48,103	$48,103	$48,103	$48,103	$48,103	$96,206	$594,768
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,193,077	$1,193,077
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)													$1,193,077	
3a. Less: Accumulated Depreciation													$1,387	
4. CWIP Non-Interest Bearing	$983,131	$983,131	$1,013,526	$1,045,984	$1,126,989	$1,193,077	$1,241,180	$1,289,282	$1,337,385	$1,385,488	$1,433,591	$1,481,693	$384,822	
5. Net Investment (Lines 2 - 3 + 4)	$983,131	$983,131	$1,013,526	$1,045,984	$1,126,989	$1,193,077	$1,241,180	$1,289,282	$1,337,385	$1,385,488	$1,433,591	$1,481,693	$1,576,512	
6. Average Net Investment		$983,131	$998,328	$1,029,755	$1,086,486	$1,160,033	$1,217,128	$1,265,231	$1,313,334	$1,361,437	$1,409,539	$1,457,642	$1,529,103	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5,450	$5,534	$5,708	$6,022	$6,430	$6,747	$6,954	$7,218	$7,483	$7,747	$8,011	$8,404	$81,708
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,107	$1,124	$1,159	$1,223	$1,306	$1,370	$1,427	$1,482	$1,536	$1,590	$1,645	$1,725	$16,693
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,387	$1,387
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$6,556	$6,658	$6,867	$7,245	$7,736	$8,117	$8,381	$8,700	$9,019	$9,337	$9,656	$11,516	$99,788

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
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Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period of 1.657% based on the May 2020 Earning Surveillance Report.

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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
54 - Coal Combustion Residuals														
Base														
1. Investments														
a. Expenditures/Additions		$3,516,164	($2,840,848)	$1,724,261	$1,142,026	$1,361,035	$639,947	$639,947	$639,947	$639,947	$639,947	$639,947	$1,279,895	$10,022,217
b. Clearings to Plant		$0	$0	$0	$0	$0	$34,895,696	$0	$0	$0	$0	$0	$23,633,634	$58,529,330
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$46,922,718	$46,922,718	$46,922,718	$46,398,629	$46,398,629	$46,398,629	$81,294,324	$81,294,324	$81,294,324	$81,294,324	$81,294,324	$81,294,324	$104,927,958	
3a. Less: Accumulated Depreciation	$1,871,389	$1,979,044	$2,086,698	$2,194,352	$2,302,006	$2,409,661	$2,551,048	$2,726,167	$2,901,286	$3,076,405	$3,251,525	$3,426,644	$3,624,609	
3b. Less: Capital Recovery Unamortized Balance	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	
4. CWIP Non-Interest Bearing	$53,626,692	$57,142,856	$54,302,008	$56,026,269	$57,168,294	$58,529,330	$24,273,581	$24,913,529	$25,553,476	$26,193,423	$26,833,371	$27,473,318	$5,119,579	
5. Net Investment (Lines 2 - 3 + 4)	$98,733,270	$102,141,780	$99,193,278	$100,285,795	$101,320,167	$102,573,548	$108,072,108	$103,536,938	$104,001,764	$104,466,592	$104,931,421	$105,396,249	$106,478,178	
6. Average Net Investment		$100,437,525	$100,667,529	$99,739,537	$100,802,981	$101,946,857	$102,822,828	$103,304,522	$103,769,350	$104,234,178	$104,699,006	$105,163,835	$105,937,213	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$556,731	$558,006	$552,862	$558,757	$565,097	$569,953	$567,778	$570,333	$572,888	$575,442	$577,997	$582,248	$6,808,092
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$113,052	$113,311	$112,267	$113,464	$114,751	$115,737	$116,548	$117,073	$117,597	$118,121	$118,646	$119,518	$1,390,087
8. Investment Expenses														
a. Depreciation (e)		$107,654	$107,654	$107,654	$107,654	$107,654	$141,387	$175,119	$175,119	$175,119	$175,119	$175,119	$197,965	$1,753,220
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$777,438	$778,972	$772,783	$779,875	$787,503	$827,077	$859,445	$862,525	$865,604	$868,683	$871,762	$899,731	$9,951,398

(a) Applicable to reserve salvage and removal cost
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 68-70.
(c) The Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019
Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 Earning Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earning Surveillance Report and the Debt Component for
the Jul. – Dec. 2020 period is 1.3538% based on the May 2019 Earning Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-8E, pages 68-70.
(f) Applicable amortization period(s). See Form 42-8E, pages 68-70.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
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Equity Component: Gross-up factor for taxes is 1/0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Jun. 2020 period of 6.604% based on the May 2019 Earning Surveillance Report
and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2020 period of 6.362% based on the May 2020 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2020 period of 1.661% based on the May 2019 Earning Surveillance Report and the Debt Component for the
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JANUARY 2020 THROUGH DECEMBER 2020

	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1 Working Capital Dr (Cr)														
a. 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
b. 158.200 Allowances Withheld	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 182.300 Other Regulatory Assets-Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
d 254.900Other Regulatory Liabilities-Gains	($242)	($235)	($228)	($220)	($220)	($227)	($227)	($219)	($212)	($205)	($197)	($190)	($183)	
2 Total Working Capital	($242)	($235)	($228)	($220)	($220)	($227)	($227)	($219)	($212)	($205)	($197)	($190)	($183)	
3 Average Net Working Capital Balance		($238)	($231)	($224)	($220)	($223)	($227)	($223)	($216)	($208)	($201)	($194)	($186)	
4 Return on Average Net Working Capital Balance														
a. Equity Component grossed up for taxes	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	
b. Debt Component	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
5. Total Return Component	($2)	($2)	($2)	($1)	($1)	($1)	($2)	($1)	($1)	($1)	($1)	($1)	($1)	($17)
6. Expense Dr (Cr)														
a. 411.800 Gains from Dispositions of Allowances	($44)	($7)	($7)	($7)			($7)	($7)	($7)	($7)	($7)	($7)	($7)	
b. 411.900 Losses from Dispositions of Allowances	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
c. 509.000 Allowance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7. Net Expense (Lines 6a+6b+6c)	($44)	($7)	($7)	($7)			($7)	($7)	($7)	($7)	($7)	($7)	($7)	($73)
8. Total System Recoverable Expenses (Lines 5+6)	($46)	($9)	($9)	($9)	($1)	($1)	($9)	($9)	($9)	($9)	($9)	($9)	($9)	

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

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

(c) Line 8a times Line 9

(d) Line 8b times Line 10

(e) Line 5 is reported on Capital Schedule

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

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

Project	Class ID	Plant	Unit	Utility	DEPR RATE	Sum of Dec-19	Sum of Dec-20
002-LOW NOX BURNER TECHNOLOGY	02 - Steam Generation Plant	Turkey Pt	Turkey Pt U1	31200	0.00%	-	-
002-LOW NOX BURNER TECHNOLOGY Total						-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	65,605	65,605
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee U1	31100	1.74%	56,430	56,430
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	424,505	424,505
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee U2	31100	1.83%	56,333	56,333
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	468,728	468,728
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin	Martin Comm	31670	7-Year	-	(4,473)
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	515,653	515,653
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale GTs	34300	8.25%	10,225	10,225
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Myers	FtMyers U2	34300	3.46%	365,000	365,000
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Myers	FtMyers U3	34100	3.38%	6,098	6,098
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Myers	FtMyers U3	34300	4.54%	71,939	71,939
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Myers	FtMyers U3 SC Peaker	34300	3.04%	69,082	69,082
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Manatee	Manatee U3	34300	3.35%	87,691	87,691
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin	Martin U3	34300	4.49%	615,919	615,469
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin	Martin U4	34300	3.92%	598,036	598,036
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin	Martin U8	34300	3.37%	13,693	13,693
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford	Sanford U4	34300	4.00%	310,021	310,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford	Sanford U5	34300	4.12%	273,035	273,035
003-CONTINUOUS EMISSION MONITORING Total						**4,007,994**	**4,003,071**
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	3,111,263	3,111,263
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	174,543	174,543
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	104,845	104,845
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	127,429	127,429
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	133,572	133,572
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin	Martin Comm U1&2	31100	2.52%	65,093	65,093
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34200	3.09%	898,111	898,111
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale GTs	34200	4.73%	584,290	584,290
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34200	7.84%	133,479	133,479
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Ft Myers	FtMyers U3	34200	3.58%	18,616	18,616
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Martin	Martin Comm U3&4	34200	2.42%	455,941	455,941
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	08 - General Plant	General Plant	General Plant	39000	1.50%	5,837,840	8,224,667
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total						**11,645,022**	**14,031,849**
007-RELOCATE TURBINE LUBE OIL PIPING	03 - Nuclear Generation Plant	St Lucie	StLucie U1	32300	5.11%	31,030	31,030
007-RELOCATE TURBINE LUBE OIL PIPING Total						**31,030**	**31,030**
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	46,882	46,882
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee	Manatee U1	31100	1.74%		52,481
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin	Martin Comm	31650	5-Year	227,249	263,879
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin	Martin Comm	31670	7-Year	298,813	258,350
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34100	2.20%	358,636	358,636
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Ft Myers	FtMyers U2	34100	2.34%		405,369
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Pt Everglades	PtEverglades U5	34100	2.64%	22,550	22,550
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Sanford	Sanford Comm	34100	2.40%	15,922	15,922
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36670	2.00%	2,995	2,995
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	General Plant	39000	1.50%	4,413	4,413
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total						**977,460**	**1,431,477**
010-REROUTE STORMWATER RUNOFF	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	117,794	117,794
010-REROUTE STORMWATER RUNOFF Total						**117,794**	**117,794**
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer	Scherer Comm	31100	1.51%	524,873	524,873
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer	Scherer Comm	31200	2.23%	328,762	328,762
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer	Scherer Comm	31400	2.08%	689	689
012-SCHERER DISCHARGE PIPELINE Total						**854,324**	**854,324**
016-ST.LUCIE TURTLE NETS	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	6,909,559	6,909,559
016-ST.LUCIE TURTLE NETS Total						**6,909,559**	**6,909,559**
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin	Martin U1	31200	0.00%	-	-
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin	Martin U2	31200	0.00%	-	-
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total						-	-
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	601,217	601,217
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	2,271,574	2,271,574
022-PIPELINE INTEGRITY MANAGEMENT Total						**2,872,791**	**2,872,791**
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	1,243,306	1,243,306
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	33,272	33,272
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee Comm	31500	2.34%	26,325	26,325
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	45,750	45,750
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	37,431	37,431
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	37,158	37,158
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	St Lucie	StLucie U1	32300	5.11%	712,225	712,225
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	St Lucie	StLucie U1	32400	3.20%	745,335	745,335
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	St Lucie	StLucie U2	32300	3.86%	552,390	552,390
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32100	3.13%	990,124	990,124
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32570	7-Year	245,362	245,362
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34100	2.20%	189,219	189,219
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34200	3.09%	1,480,169	1,480,169
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34300	5.20%	28,250	28,250

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

Project	Class ID	Plant	Unit	Utility	DEPR RATE	Sum of Dec-19	Sum of Dec-20
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale GTs	34200	4.73%	513,250	513,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34100	7.40%	98,715	98,715
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34200	7.84%	629,983	629,983
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34500	7.77%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U2	34100	2.34%		425,728
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U2	34300	3.46%	49,727	49,727
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U3	34500	3.40%		12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U3 SC Peaker	34500	3.40%	12,430	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin	Martin Comm U3&4	34100	2.24%	523,498	1,080,186
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin	Martin U8	34200	2.70%	84,868	84,868
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Pt Everglades	PtEverglades Comm	34200	2.90%	2,728,283	2,728,283
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Pt Everglades	PtEverglades U5	34200	2.90%		286,434
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Sanford	Sanford Comm	34100	2.40%	288,383	288,383
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Radial-Retail	Radial-Retail	35200	1.70%	6,946	6,946
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35200	1.70%	1,142,640	1,142,640
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	2.04%	2,903,187	2,902,891
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35800	1.87%	65,655	65,655
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36100	1.75%	3,336,463	3,506,546
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36670	2.00%	70,499	70,499
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	08 - General Plant	General Plant	General Plant	39000	1.50%	146,691	146,691
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total						**18,979,966**	**20,418,601**
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	16,470,024	16,470,024
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	15,393,694	15,393,694
024-GAS REBURN Total						**31,863,719**	**31,863,719**
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	Pt Everglades	PtEverglades U1	31100	0.00%	-	-
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	Pt Everglades	PtEverglades U2	31100	0.00%	-	-
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	Pt Everglades	PtEverglades U3	31100	0.00%	-	-
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	Pt Everglades	PtEverglades U4	31100	0.00%	-	-
025-PPE ESP TECHNOLOGY Total						-	-
026-UST REPLACEMENT/REMOVAL	08 - General Plant	General Plant	General Plant	39000	1.50%	115,447	115,447
026-UST REPLACEMENT/REMOVAL Total						**115,447**	**115,447**
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	Cape Canaveral	CapeCanaveral Comm	34100	2.69%	771,310	771,310
028-CWA 316B PHASE II RULE Total						**771,310**	**771,310**
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	102,052	102,052
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	20,059,060	20,059,060
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee U1	31400	4.03%	7,240,124	7,240,124
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	20,457,354	20,457,354
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee U2	31400	3.72%	7,905,907	7,905,907
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer Comm U3&4	31200	2.32%	3,179,403	4,976,687
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31100	2.30%	82,366,984	82,366,984
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	254,475,936	254,475,936
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31400	1.89%	(94,224)	(94,224)
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31500	2.49%	19,615,426	19,615,426
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31600	1.88%	399,586	399,586
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31670	7-Year	268	-
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale GTs	34300	8.25%	110,242	110,242
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34300	8.22%	57,855	57,855
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin	Martin Comm U3&4	34100	2.24%	699,143	699,143
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin	Martin Comm U3&4	34300	2.56%	244,343	244,343
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin	Martin Comm U3&4	34500	2.04%	292,499	292,499
031-CLEAN AIR INTERSTATE RULE-CAIR	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36500	2.57%	1,313	1,313
031-CLEAN AIR INTERSTATE RULE-CAIR Total						**417,113,272**	**418,910,287**
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer	Scherer Comm U3&4	31200	2.32%	(1,234,037)	(1,234,037)
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	110,494,775	110,565,526
033-CLEAN AIR MERCURY RULE-CAMR Total						**109,260,738**	**109,331,489**
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANC	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%		-
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE Total							-
035-MARTIN PLANT DRINKING WATER COMP	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	235,391	235,391
035-MARTIN PLANT DRINKING WATER COMP Total						**235,391**	**235,391**
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	7,601,405	7,601,405
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32100	3.13%	9,855,399	9,855,399
036-LOW LEV RADI WSTE-LLW Total						**17,456,804**	**17,456,804**
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34000	0.00%	255,507	255,507
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34100	3.49%	5,263,916	5,263,916
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34300	3.36%	115,292,583	115,297,623
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34500	3.65%	26,746,246	26,746,246
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34630	3-Year	15,749	7,279
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34650	5-Year	51,031	24,247
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34670	7-Year	182,866	152,115
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35200	1.70%	7,427	7,427
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	2.04%	1,004,027	1,004,027
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35310	2.64%	1,695,869	1,695,869
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35500	2.32%	394,418	394,418
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35600	2.38%	191,358	191,358
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36100	1.75%	540,994	540,994
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36200	1.90%	1,890,938	1,890,938

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

Project	Class ID	Plant	Unit	Utility	DEPR RATE	Sum of Dec-19	Sum of Dec-20
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39220	10.00%	28,426	28,426
037-DE SOTO SOLAR PROJECT Total						153,561,354	153,500,389
038-SPACE COAST SOLAR PROJECT	01 - Intangible Plant	Intangible Plant	Intangible Plant	30300	various	6,359,027	6,359,027
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34100	3.45%	3,893,263	3,893,263
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34300	3.30%	51,550,587	51,550,587
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34500	3.51%	6,126,699	6,126,699
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34650	5-Year	35,202	0
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34670	7-Year	-	337
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	2.04%	928,529	928,529
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35310	2.64%	1,328,699	1,328,699
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36100	1.75%	274,858	274,858
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36200	1.90%	62,689	62,689
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39220	10.00%	31,858	31,858
038-SPACE COAST SOLAR PROJECT Total						70,591,411	70,556,546
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin	Martin U8	34300	3.37%	423,126	423,126
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34000	0.00%	216,844	216,844
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34100	2.99%	20,756,023	20,756,023
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34300	2.88%	398,729,596	400,842,239
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34500	2.99%	4,122,852	4,170,831
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34600	2.85%	56,448	56,448
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34670	7-Year	138,981	138,981
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35500	2.32%	603,692	603,692
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35600	2.38%	364,159	364,159
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36660	1.42%	94,476	94,476
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36760	1.96%	2,728	2,728
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39220	10.00%	121,101	121,101
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39240	2.63%	332,682	332,682
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39290	4.99%	88,938	88,938
039-MARTIN SOLAR PROJECT Total						426,051,646	428,212,267
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Cape Canaveral	CapeCanaveral Comm	34300	0.00%	4,042,459	4,042,459
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Dania Beach EC U7	Dania Beach EC U7	34300	44 mos.		7,927,191
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34300	44 mos.	7,891,910	-
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Ft Myers	FtMyers U2	34300	3.46%	5,581,733	5,603,547
041-PRV MANATEE HEATING SYSTEM	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	various	276,404	276,404
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36100	various	73,267	73,267
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36200	various	471,542	471,542
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36500	various	307,599	307,599
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36660	various	221,326	221,326
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36760	various	168,995	168,995
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36910	various	607	607
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36420	various	36,431	36,431
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36410	various	137,247	137,247
041-PRV MANATEE HEATING SYSTEM Total						19,209,521	19,266,616
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32100	3.13%	39,915,222	44,402,659
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32500	3.67%	181,743	896,065
042-PTN COOLING CANAL MONITORING SYS	05 - Other Generation Plant	Turkey Pt	Turkey Pt U5	34100	2.33%		14,859,266
042-PTN COOLING CANAL MONITORING SYS Total						40,096,965	60,157,990
044-Barley Barber Swamp Iron Mitiga	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	164,719	164,719
044-Barley Barber Swamp Iron Mitiga Total						164,719	164,719
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	153,660	153,660
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	44,854,496	44,485,716
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U1	31500	4.11%	4,524,074	4,524,074
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U1	31600	3.91%	1,021,918	1,021,918
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	51,505,171	52,279,530
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U2	31500	4.48%	4,793,798	4,793,798
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U2	31600	4.79%	1,174,454	1,174,454
045-800 MW UNIT ESP PROJECT Total						108,027,572	108,433,151
047-NPDES Permit Renewal Requiremnt	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%		-
047-NPDES Permit Renewal Requiremnt	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32300	7.22%		38,004
047-NPDES Permit Renewal Requiremnt Total							38,004
050-STEAM ELEC EFFLUENT GUIDELI REV	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%		1,193,077
050-STEAM ELEC EFFLUENT GUIDELI REV Total							1,193,077
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer	Scherer Comm	31100	1.51%	208,650	208,650
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer	Scherer Comm U3&4	31200	2.32%		58,529,330
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	46,714,068	46,189,978
054-COAL COMBUSTION RESIDUALS Total						46,922,718	104,927,958
123-PROTECTED SPECIES PROJECT	05 - Other Generation Plant	Ft Myers	FtMyers U2	34100	2.34%	-	-
123-PROTECTED SPECIES PROJECT Total						-	-
Grand Total						**1,487,447,141**	**1,575,805,658**

FLORIDA POWER & LIGHT COMPANY **FORM 42-9E**
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2019 EARNINGS SURVEILLANCE REPORT

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

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

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

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

Note:

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

FLORIDA POWER & LIGHT COMPANY **FORM 42-9E**
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2020 EARNINGS SURVEILLANCE REPORT

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

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

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

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

Note:

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

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-1P

JANUARY 2021 THROUGH DECEMBER 2021

	Energy	CP Demand	GCP Demand	Total
1. Total Jurisdictional Revenue Requirements for the Projected Period				
a. Projected O&M Activities [b]	$17,224,961	$8,304,778	$2,927,122	$28,456,861
b. Projected Capital Projects [c]	$12,942,278	$134,775,526	$0	$147,717,804
c. Total Jurisdictional Revenue Requirements [d]	$30,167,239	$143,080,304	$2,927,122	$176,174,665
2. True-up for Estimated Over/(Under) Recovery [e]	$997,176	$3,676,135	$90,474	$4,763,785
3. Final True-up Over/(Under) [f]	$2,343,421	$11,398,155	$346,367	$14,087,943
4. Total Jurisdictional Amount to be Recovered/(Refunded) [g]	$26,826,643	$128,006,014	$2,490,281	$157,322,938
5. Total Projected Jurisdictional Amount Adjusted for Taxes [h]	$26,845,958	$128,098,178	$2,492,074	$157,436,210

(b) Form 42-2P-1 pg. 2, Columns 6 through 8
(c) Form 42-3P-1 pg. 2, Columns 6 and 7
[d] Lines 1a + 1b
[e] For the current period January 2020 - December 2020 (Form 42-1E, Line 4, filed on July 31, 2020)
[f] For the period January 2019 - December 2019 (Revised Form 42-1A, Line 7, filed on April 1, 2020)
[g] (Line 1 - Line 2 - Line 3)
[h] Line 4 x Revenue Tax Multiplier 1.00072

Note: Allocation to energy and demand in each period are in proportion to the respective period split of costs.
True-up costs are split in proportion to the split of actual demand-related and energy-related costs from respective true-up periods.

Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 4
PARTY: RBD-3
DESCRIPTION: Appendix I - Environmental Cost Recovery Projections - January 2021 - December 2021 Commission Forms...

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-2P

JANUARY 2021 THROUGH DECEMBER 2021

O&M ACTIVITIES

O&M Project	Strata	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1 - Air Operating Permit Fees	Base	$12,083	$12,083	$12,083	$12,083	$12,083	$12,083	$12,083	$12,083	$12,083	$12,083	$12,083	$12,083	$145,000
1 - Air Operating Permit Fees	Intermediate	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$3,012	$36,145
1 - Air Operating Permit Fees	Peaking	$297	$297	$297	$297	$297	$297	$297	$297	$297	$297	$297	$297	$3,570
3a - Continuous Emission Monitoring Systems	Intermediate	$95,186	$18,009	$18,009	$24,259	$18,009	$18,009	$24,259	$18,009	$18,009	$24,259	$18,554	$19,208	$313,775
3a - Continuous Emission Monitoring Systems	Peaking	$12,934	$7,893	$5,251	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$50,828
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$880	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$880
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$0	$0	$150,000	$6,224	$500	$1,201	$0	$0	$0	$0	$0	$0	$157,925
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$4,620	$0	$50,000	$58,776	$50,000	$70,001	$0	$0	$0	$0	$0	$0	$233,397
8a - Oil Spill Clean-up/Response Equipment	Intermediate	$2,727	$2,727	$2,727	$2,727	$2,727	$2,727	$2,186	$2,186	$2,186	$2,186	$2,186	$2,186	$29,473
8a - Oil Spill Clean-up/Response Equipment	Peaking	$22,060	$22,060	$22,060	$22,060	$22,060	$22,060	$17,684	$17,684	$17,684	$17,684	$17,684	$17,684	$238,467
14 - NPDES Permit Fees	Base	$11,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,500
14 - NPDES Permit Fees	Intermediate	$28,260	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,260
14 - NPDES Permit Fees	Peaking	$29,440	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29,440
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$234,552	$235,802	$259,552	$260,802	$235,802	$220,802	$220,802	$220,802	$220,802	$280,802	$280,802	$255,802	$2,927,122
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$74,420	$125,587	$124,502	$125,752	$125,752	$75,752	$75,752	$75,752	$65,752	$125,752	$135,752	$135,587	$1,266,116
21 - St. Lucie Turtle Nets	Base	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$30,700	$368,400
22 - Pipeline Integrity Management	Intermediate	$0	$0	$0	$32,157	$0	$0	$0	$0	$0	$0	$0	$0	$32,157
22 - Pipeline Integrity Management	Peaking	$0	$0	$0	$45,343	$0	$0	$0	$0	$0	$0	$0	$0	$45,343
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$49,792	$51,092	$51,092	$49,007	$49,327	$49,222	$49,327	$50,112	$50,682	$49,007	$50,197	$51,085	$599,938
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$2,068	$2,068	$2,068	$2,068	$2,068	$2,068	$2,068	$2,068	$2,068	$2,068	$2,068	$2,068	$24,822
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$632	$632	$632	$632	$632	$632	$632	$632	$632	$632	$632	$632	$7,578
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$16,032	$15,914	$16,350	$16,228	$16,107	$16,228	$16,228	$16,228	$16,228	$16,107	$16,228	$16,350	$194,230
24 - Manatee Reburn	Peaking	$0	$89,344	$122,988	$0	$0	$0	$0	$0	$0	$0	$0	$0	$212,332
27 - Lowest Quality Water Source	Intermediate	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$8,500	$102,000
28 - CWA 316(b) Phase II Rule	Base	$22,453	$11,709	$33,499	$31,830	$14,500	$1,102	$7,647	$11,491	$1,044	$996	$1,044	$1,091	$138,407
28 - CWA 316(b) Phase II Rule	Intermediate	$21,489	$20,759	$10,628	$10,539	$35,451	$31,428	$26,939	$26,939	$26,939	$26,851	$26,939	$32,028	$296,931
28 - CWA 316(b) Phase II Rule	Peaking	$5,405	$5,148	$6,098	$5,833	$5,567	$5,833	$5,833	$5,833	$5,833	$5,567	$5,833	$6,098	$68,879
29 - SCR Consumables	Intermediate	$27,736	$72,412	$41,236	$76,236	$27,736	$27,736	$27,736	$27,736	$27,736	$54,892	$27,736	$27,736	$466,664
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$313,254	$313,254	$313,254	$313,254	$313,254	$313,254	$313,254	$313,254	$313,254	$313,254	$313,254	$313,254	$3,759,050
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$11,000	$132,000
33 - MATS Project	Base	$201,732	$201,732	$201,732	$201,732	$201,732	$201,732	$201,732	$201,732	$201,732	$201,732	$201,732	$201,732	$2,420,782
37 - DeSoto Next Generation Solar Energy Center	Solar	$44,150	$33,518	$58,975	$39,318	$33,816	$43,969	$39,723	$38,016	$45,891	$92,492	$40,319	$36,100	$546,286
38 - Space Coast Next Generation Solar Energy Center	Solar	$24,484	$21,812	$19,878	$19,176	$22,601	$28,874	$18,962	$26,772	$19,261	$18,259	$22,700	$25,327	$268,106
39 - Martin Next Generation Solar Energy Center	Intermediate	$333,442	$327,556	$345,598	$339,695	$333,792	$339,695	$339,695	$339,695	$339,695	$334,589	$343,202	$348,897	$4,065,551
41 - Manatee Temporary Heating System	Intermediate	$23,200	$23,200	$23,200	$5,200	$5,000	$5,000	$5,000	$5,000	$5,000	$50,200	$22,700	$23,200	$195,900
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$532,827	$551,615	$739,585	$1,011,173	$1,238,908	$1,074,139	$1,237,964	$954,470	$774,634	$849,481	$585,315	$195,998	$9,746,110
45 - 800 MW Unit ESP	Peaking	$19,849	$25,425	$20,751	$18,045	$28,131	$19,849	$18,947	$28,131	$18,947	$19,849	$27,229	$18,947	$264,099
47 - NPDES Permit Renewal Requirements	Base	$50,000	$0	$2,585	$0	$0	$0	$0	$0	$0	$2,585	$0	$0	$55,170
47 - NPDES Permit Renewal Requirements	Intermediate	$0	$0	$12,913	$0	$0	$0	$5,200	$0	$5,200	$0	$2,513	$0	$25,826
48 - Industrial Boiler MACT	Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,400	$0	$0	$10,400
48 - Industrial Boiler MACT	Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$54,600	$0	$0	$54,600
51 - Gopher Tortoise Relocations	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000	$0	$2,000
51 - Gopher Tortoise Relocations	Peaking	$0	$0	$0	$0	$0	$0	$0	$13,262	$13,262	$0	$0	$11,000	$37,523
123 - Protected Species Project	Intermediate	$0	$0	$25,000	$0	$0	$25,000	$0	$0	$25,000	$0	$0	$25,000	$100,000
	Total	$2,270,718	$2,244,859	$2,745,756	$2,786,409	$2,851,814	$2,664,655	$2,725,912	$2,464,145	$2,285,813	$2,622,587	$2,214,962	$1,835,352	$29,712,982

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-2P

JANUARY 2021 THROUGH DECEMBER 2021

O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
O&M Project	Strata	Monthly Data	Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	CP Demand	Energy	GCP Demand
1 - Air Operating Permit Fees	Base	$145,000	95.6788%	$138,734	$0	$138,734	$0
1 - Air Operating Permit Fees	Intermediate	$36,145	94.9979%	$34,337	$0	$34,337	$0
1 - Air Operating Permit Fees	Peaking	$3,570	95.2675%	$3,401	$0	$3,401	$0
3a - Continuous Emission Monitoring Systems	Intermediate	$313,775	94.9979%	$298,080	$0	$298,080	$0
3a - Continuous Emission Monitoring Systems	Peaking	$50,828	95.2675%	$48,422	$0	$48,422	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$880	95.6891%	$842	$842	$0	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$157,925	95.0081%	$150,042	$150,042	$0	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$233,397	95.2778%	$222,375	$222,375	$0	$0
8a - Oil Spill Clean-up/Response Equipment	Intermediate	$29,473	94.9979%	$27,999	$0	$27,999	$0
8a - Oil Spill Clean-up/Response Equipment	Peaking	$238,467	95.2675%	$227,181	$0	$227,181	$0
14 - NPDES Permit Fees	Base	$11,500	95.6891%	$11,004	$11,004	$0	$0
14 - NPDES Permit Fees	Intermediate	$28,260	95.0081%	$26,849	$26,849	$0	$0
14 - NPDES Permit Fees	Peaking	$29,440	95.2778%	$28,050	$28,050	$0	$0
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$2,927,122	100.0000%	$2,927,122	$0	$0	$2,927,122
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$1,266,116	90.2300%	$1,142,416	$1,142,416	$0	$0
21 - St. Lucie Turtle Nets	Base	$368,400	95.6891%	$352,519	$352,519	$0	$0
22 - Pipeline Integrity Management	Intermediate	$32,157	95.0081%	$30,552	$30,552	$0	$0
22 - Pipeline Integrity Management	Peaking	$45,343	95.2778%	$43,202	$43,202	$0	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$599,938	100.0000%	$599,938	$599,938	$0	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$24,822	95.0081%	$23,583	$23,583	$0	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$7,578	95.2778%	$7,220	$7,220	$0	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$194,230	90.2300%	$175,253	$175,253	$0	$0
24 - Manatee Reburn	Peaking	$212,332	95.2675%	$202,283	$0	$202,283	$0
27 - Lowest Quality Water Source	Intermediate	$102,000	95.0081%	$96,908	$96,908	$0	$0
28 - CWA 316(b) Phase II Rule	Base	$138,407	95.6891%	$132,440	$132,440	$0	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$296,931	95.0081%	$282,109	$282,109	$0	$0
28 - CWA 316(b) Phase II Rule	Peaking	$68,879	95.2778%	$65,626	$65,626	$0	$0
29 - SCR Consumables	Intermediate	$466,664	94.9979%	$443,321	$0	$443,321	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,759,050	95.6788%	$3,596,613	$0	$3,596,613	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$132,000	95.2675%	$125,753	$0	$125,753	$0
33 - MATS Project	Base	$2,420,782	95.6788%	$2,316,175	$0	$2,316,175	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$546,286	95.6891%	$522,736	$522,736	$0	$0
38 - Space Coast Next Generation Solar Energy Center	Solar	$268,106	95.6891%	$256,548	$256,548	$0	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$4,065,551	95.0081%	$3,862,604	$3,862,604	$0	$0
41 - Manatee Temporary Heating System	Intermediate	$195,900	94.9979%	$186,101	$0	$186,101	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$9,746,110	95.6788%	$9,324,960	$0	$9,324,960	$0
45 - 800 MW Unit ESP	Peaking	$264,099	95.2675%	$251,601	$0	$251,601	$0
47 - NPDES Permit Renewal Requirements	Base	$55,170	95.6891%	$52,792	$52,792	$0	$0
47 - NPDES Permit Renewal Requirements	Intermediate	$25,826	95.0081%	$24,537	$24,537	$0	$0
48 - Industrial Boiler MACT	Base	$10,400	95.6891%	$9,952	$9,952	$0	$0
48 - Industrial Boiler MACT	Peaking	$54,600	95.2778%	$52,022	$52,022	$0	$0
51 - Gopher Tortoise Relocations	Intermediate	$2,000	95.0081%	$1,900	$1,900	$0	$0
51 - Gopher Tortoise Relocations	Peaking	$37,523	95.2778%	$35,751	$35,751	$0	$0
123 - Protected Species Project	Intermediate	$100,000	95.0081%	$95,008	$95,008	$0	$0
	Total	$29,712,982		$28,456,861	$8,304,778	$17,224,961	$2,927,122

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-2P

JANUARY 2021 THROUGH DECEMBER 2021

O&M ACTIVITIES

RAD - ECRC - 42 - 2P	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2. Total of O&M Activities	$2,270,718	$2,244,859	$2,745,756	$2,786,409	$2,851,814	$2,664,655	$2,725,912	$2,464,145	$2,285,813	$2,622,587	$2,214,962	$1,835,352	$29,712,982
3. Recoverable Costs Jurisdictionalized on Energy - Base	$1,059,897	$1,078,684	$1,266,655	$1,538,243	$1,765,977	$1,601,209	$1,765,033	$1,481,539	$1,301,703	$1,376,550	$1,112,385	$723,067	$16,070,942
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$151,861	$119,359	$88,183	$111,433	$56,483	$56,483	$62,192	$55,942	$55,942	$134,548	$74,187	$75,341	$1,041,958
Recoverable Costs Jurisdictionalized on Energy - Peaking	$66,141	$156,019	$182,348	$54,152	$64,239	$55,957	$50,679	$59,863	$50,679	$51,581	$58,961	$50,679	$901,295
Recoverable Costs Jurisdictionalized on Energy - Solar	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$90,452	$141,501	$140,852	$141,981	$141,859	$91,981	$91,981	$91,981	$81,981	$141,859	$151,981	$151,938	$1,460,345
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$115,533	$42,409	$66,784	$62,530	$45,200	$31,802	$38,347	$42,191	$31,744	$44,681	$31,744	$31,791	$584,757
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$393,760	$358,883	$554,708	$399,184	$380,312	$407,893	$382,403	$377,203	$407,403	$372,009	$385,223	$416,493	$4,835,473
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$40,097	$5,779	$56,729	$110,583	$56,199	$76,465	$6,464	$19,726	$19,726	$60,799	$6,464	$17,729	$476,760
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$68,634	$55,330	$78,853	$58,494	$56,417	$72,843	$58,685	$64,787	$65,152	$110,751	$63,019	$61,427	$814,392
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$49,792	$51,092	$51,092	$49,007	$49,327	$49,222	$49,327	$50,112	$50,682	$49,007	$50,197	$51,085	$599,938
5. Recoverable Costs Jurisdictionalized on GCP Demand - Distribution	$234,552	$235,802	$259,552	$260,802	$235,802	$220,802	$220,802	$220,802	$220,802	$280,802	$280,802	$255,802	$2,927,122
6. Retail Production Energy Jurisdictional Factor - Base	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	
Retail Production Energy Jurisdictional Factor - Intermediate	94.99791%	94.99791%	94.99791%	94.99791%	94.99791%	94.99791%	94.99791%	94.99791%	94.99791%	94.99791%	94.99791%	94.99791%	
Retail Production Energy Jurisdictional Factor - Peaking	95.26752%	95.26752%	95.26752%	95.26752%	95.26752%	95.26752%	95.26752%	95.26752%	95.26752%	95.26752%	95.26752%	95.26752%	
Retail Production Energy Jurisdictional Factor - Solar	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	95.67878%	
7. Retail Distribution Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
Retail Transmission Demand Jurisdictional Factor	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	
Retail Production Demand Jurisdictional Factor - Base	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	
Retail Production Demand Jurisdictional Factor - Intermediate	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	
Retail Production Demand Jurisdictional Factor - Peaking	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	
Retail Production Demand Jurisdictional Factor - Solar	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	
8. Jurisdictional Recoverable Costs- Transmission	$81,615	$127,677	$127,091	$128,109	$127,999	$82,994	$82,994	$82,994	$73,971	$127,999	$137,132	$137,093	$1,317,669
Jurisdictional Recoverable Costs - Production - Base	$1,124,649	$1,072,653	$1,275,825	$1,531,606	$1,732,917	$1,562,448	$1,725,456	$1,457,891	$1,275,829	$1,359,821	$1,094,692	$722,243	$15,936,030
Jurisdictional Recoverable Costs - Production - Intermediate	$518,369	$454,357	$610,789	$485,117	$414,985	$441,189	$422,395	$411,518	$440,210	$481,257	$436,470	$467,275	$5,583,930
Jurisdictional Recoverable Costs - Production - Peaking	$101,214	$154,142	$227,769	$156,950	$114,744	$126,163	$54,439	$75,824	$67,074	$107,068	$62,329	$65,172	$1,312,887
Jurisdictional Recoverable Costs - Production - Solar	$65,675	$52,945	$75,454	$55,973	$53,985	$69,703	$56,155	$61,995	$62,343	$105,977	$60,302	$58,779	$779,284
Jurisdictional Recoverable Costs - Distribution	$284,344	$286,894	$310,644	$309,809	$285,129	$270,024	$270,129	$270,914	$271,484	$329,809	$330,999	$306,887	$3,527,060
9. Total Jurisdictional Recoverable Costs for O&M Activities	$2,175,865	$2,148,667	$2,627,571	$2,667,563	$2,729,759	$2,552,520	$2,611,568	$2,361,134	$2,190,911	$2,511,930	$2,121,923	$1,757,448	$28,456,861

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-3P

JANUARY 2021 THROUGH DECEMBER 2021

CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

Capital Projects	Strata	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
02 - Low NOX Burner Technology	Peaking	$4,630	$4,609	$4,588	$4,567	$4,546	$4,526	$4,505	$4,484	$4,463	$4,442	$4,421	$4,400	$54,180
03 - Continuous Emission Monitoring Systems	Base	$2,257	$2,249	$2,241	$2,233	$2,225	$2,217	$2,209	$2,201	$2,193	$2,185	$2,177	$2,169	$26,558
03 - Continuous Emission Monitoring Systems	Intermediate	$22,085	$21,724	$21,673	$21,636	$21,574	$21,510	$21,447	$21,383	$21,320	$21,256	$21,193	$21,112	$257,912
03 - Continuous Emission Monitoring Systems	Peaking	$13,610	$13,568	$13,526	$13,484	$13,442	$13,400	$13,358	$13,315	$13,273	$13,231	$13,189	$13,147	$160,543
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$151	$151	$151	$151	$151	$151	$151	$151	$151	$151	$151	$151	$1,809
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$61,425	$61,357	$61,288	$61,219	$61,150	$61,081	$61,013	$60,944	$60,875	$60,806	$60,737	$60,669	$732,564
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$18,371	$18,310	$18,249	$18,189	$18,128	$18,067	$18,007	$17,946	$17,885	$17,825	$17,764	$17,703	$216,443
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$58,300	$58,070	$57,840	$57,610	$57,380	$57,150	$56,920	$56,690	$56,460	$56,229	$55,999	$55,769	$684,415
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$122	$121	$120	$120	$119	$118	$117	$116	$115	$114	$113	$112	$1,408
08 - Oil Spill Clean-up/Response Equipment	Distribution	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$262
08 - Oil Spill Clean-up/Response Equipment	General	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$327
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$11,387	$11,424	$11,459	$11,495	$11,530	$11,565	$11,586	$11,592	$11,599	$11,605	$11,611	$11,616	$138,469
08 - Oil Spill Clean-up/Response Equipment	Peaking	$5,815	$5,594	$5,637	$5,690	$5,723	$5,756	$5,777	$5,788	$5,799	$5,810	$5,820	$5,817	$69,027
10 - Relocate Storm Water Runoff	Base	$510	$509	$507	$506	$504	$503	$501	$500	$498	$497	$496	$494	$6,026
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($15)
12 - Scherer Discharge Pipeline	Base	$2,767	$2,759	$2,750	$2,742	$2,733	$2,725	$2,716	$2,708	$2,699	$2,691	$2,682	$2,674	$32,646
20 - Wastewater Discharge Elimination & Reuse	Peaking	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$42,694
21 - St. Lucie Turtle Nets	Base	$60,990	$60,904	$60,817	$60,730	$60,644	$60,557	$60,470	$60,384	$60,297	$60,210	$60,123	$60,037	$726,163
22 - Pipeline Integrity Management	Intermediate	$11,668	$11,646	$11,623	$11,601	$11,578	$11,555	$11,533	$11,510	$11,488	$11,465	$11,442	$11,420	$138,530
22 - Pipeline Integrity Management	Peaking	$10,110	$10,090	$10,070	$10,050	$10,030	$10,010	$9,990	$9,970	$9,950	$9,930	$9,910	$9,891	$120,002
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$27,864	$27,782	$27,699	$27,617	$27,535	$27,452	$27,370	$27,288	$27,205	$27,123	$27,041	$26,958	$328,933
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$22,175	$22,140	$22,105	$22,070	$22,035	$22,000	$21,965	$21,930	$21,895	$21,860	$21,825	$21,790	$263,790
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$898	$897	$896	$894	$893	$892	$891	$889	$888	$887	$886	$885	$10,695
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$63,458	$63,290	$63,123	$62,955	$62,787	$62,767	$62,894	$63,020	$63,147	$63,475	$63,654	$63,484	$758,055
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$44,146	$43,980	$43,815	$43,649	$43,484	$43,506	$43,715	$43,924	$44,133	$44,598	$44,874	$44,705	$528,529
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$30,684	$30,639	$30,595	$30,550	$30,505	$30,461	$30,416	$30,372	$30,327	$30,282	$30,238	$30,193	$365,262
24 - Manatee Reburn	Peaking	$243,525	$242,671	$241,817	$240,962	$240,108	$239,253	$238,399	$237,544	$236,690	$235,835	$234,981	$234,126	$2,865,912
26 - UST Remove/Replacement	General	$551	$550	$549	$548	$547	$546	$545	$544	$543	$542	$541	$540	$6,545
28 - CWA 316(b) Phase II Rule	Intermediate	$6,441	$6,429	$6,418	$6,406	$6,395	$6,383	$6,372	$6,360	$6,348	$6,337	$6,325	$6,314	$76,528
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$2,999,580	$3,000,727	$2,996,040	$2,991,353	$2,986,667	$2,981,980	$2,977,293	$2,972,607	$2,967,920	$2,963,233	$2,958,547	$2,955,701	$35,751,649
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$9	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$101
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$9,391	$9,375	$9,359	$9,342	$9,326	$9,310	$9,293	$9,277	$9,261	$9,245	$9,228	$9,212	$111,620
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$728,503	$727,076	$725,648	$724,220	$722,792	$721,364	$719,936	$718,508	$717,080	$715,652	$714,224	$712,796	$8,647,795
33 - MATS Project	Base	$780,423	$778,719	$777,015	$775,311	$773,607	$771,902	$770,198	$768,494	$766,790	$765,086	$763,382	$761,678	$9,252,605
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$357,304
35 - Martin Plant Drinking Water System Compliance	Intermediate	$951	$949	$947	$946	$944	$942	$940	$938	$936	$934	$932	$930	$11,290
35 - Martin Plant Drinking Water System Compliance	Peaking	$718	$716	$715	$713	$712	$710	$709	$708	$706	$705	$703	$702	$8,517
36 - Low-Level Radioactive Waste Storage	Base	$136,680	$136,413	$136,146	$135,878	$135,611	$135,343	$135,076	$134,809	$134,541	$134,274	$134,007	$133,739	$1,622,516
37 - DeSoto Next Generation Solar Energy Center	Solar	$971,570	$968,394	$965,217	$962,041	$958,864	$955,687	$952,511	$949,351	$946,192	$942,987	$940,272	$937,584	$11,450,670
38 - Space Coast Next Generation Solar Energy Center	Solar	$452,478	$451,463	$450,045	$448,627	$447,209	$445,791	$444,373	$442,956	$441,538	$440,120	$439,182	$438,243	$5,342,024
39 - Martin Next Generation Solar Energy Center	Intermediate	$2,794,467	$2,789,253	$2,782,958	$2,776,663	$2,770,369	$2,764,074	$2,757,779	$2,751,484	$2,745,190	$2,738,895	$2,732,600	$2,729,560	$33,133,292
41 - Manatee Temporary Heating System	Distribution	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$18,284
41 - Manatee Temporary Heating System	Intermediate	$268,739	$267,426	$266,112	$264,798	$263,485	$262,171	$262,196	$262,220	$260,907	$259,593	$258,279	$256,966	$3,152,890
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$421,914	$423,097	$424,407	$425,967	$427,679	$430,351	$432,921	$436,097	$448,724	$463,989	$474,088	$490,406	$5,299,641
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$126,735	$126,542	$126,349	$126,156	$125,963	$125,770	$125,577	$125,384	$125,191	$124,998	$124,805	$124,612	$1,508,083
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$689	$687	$686	$685	$683	$682	$681	$679	$678	$677	$675	$674	$8,175
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$519	$518	$517	$516	$515	$514	$513	$512	$511	$510	$509	$508	$6,167
45 - 800 MW Unit ESP	Intermediate	$687	$685	$682	$679	$677	$674	$671	$668	$666	$663	$660	$658	$8,069
45 - 800 MW Unit ESP	Peaking	$1,556,878	$1,553,992	$1,551,105	$1,548,219	$1,545,332	$1,542,445	$1,539,559	$1,536,672	$1,533,786	$1,530,899	$1,528,013	$1,525,126	$18,492,026
47 - NPDES Permit Renewal Requirements	Base	$16,297	$17,634	$18,970	$20,307	$21,644	$26,251	$30,167	$30,121	$30,076	$30,030	$29,985	$29,940	$301,421
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$13,314	$15,088	$18,656	$22,223	$25,791	$29,358	$32,926	$36,494	$40,061	$43,629	$47,196	$60,454	$385,191
54 - Coal Combustion Residuals	Base	$932,552	$932,645	$934,308	$935,972	$937,635	$939,299	$940,962	$942,626	$944,289	$945,952	$947,616	$963,308	$11,297,162
123 - Protected Species Project	Intermediate	$0	$0	$102	$204	$204	$204	$204	$204	$981	$1,756	$1,753	$1,751	$7,364
	Total	$12,971,942	$12,957,772	$12,940,454	$12,923,407	$12,906,366	$12,893,887	$12,882,262	$12,867,275	$12,861,177	$12,858,127	$12,849,765	$12,875,635	$154,788,070

FLORIDA POWER & LIGHT COMPANY
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FORM: 42-3P

JANUARY 2021 THROUGH DECEMBER 2021

CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Capital Project	Strata	Monthly Data	Jurisdictionalization		Method of Classification	
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand
02 - Low NOX Burner Technology	Peaking	$54,180	95.2778%	$51,622	$51,622	$0
03 - Continuous Emission Monitoring Systems	Base	$26,558	95.6891%	$25,413	$25,413	$0
03 - Continuous Emission Monitoring Systems	Intermediate	$257,912	95.0081%	$245,037	$245,037	$0
03 - Continuous Emission Monitoring Systems	Peaking	$160,543	95.2778%	$152,962	$152,962	$0
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$1,809	95.6891%	$1,731	$133	$1,598
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$216,443	95.0081%	$205,638	$15,818	$189,820
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$684,415	95.2778%	$652,095	$50,161	$601,934
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$732,564	96.9888%	$710,505	$54,654	$655,850
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$1,408	95.6891%	$1,347	$104	$1,243
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$138,469	95.0081%	$131,557	$10,120	$121,437
08 - Oil Spill Clean-up/Response Equipment	Peaking	$69,027	95.2778%	$65,768	$5,059	$60,709
08 - Oil Spill Clean-up/Response Equipment	Distribution	$262	100.0000%	$262	$20	$242
08 - Oil Spill Clean-up/Response Equipment	General	$327	96.9888%	$317	$24	$293
10 - Relocate Storm Water Runoff	Base	$6,026	95.6891%	$5,766	$444	$5,323
12 - Scherer Discharge Pipeline	Base	$32,646	95.6891%	$31,239	$2,403	$28,836
21 - St. Lucie Turtle Nets	Base	$726,163	95.6891%	$694,858	$53,451	$641,408
20 - Wastewater Discharge Elimination & Reuse	Peaking	$42,694	95.2778%	$40,678	$3,129	$37,549
22 - Pipeline Integrity Management	Intermediate	$138,530	95.0081%	$131,614	$10,124	$121,490
22 - Pipeline Integrity Management	Peaking	$120,002	95.2778%	$114,336	$8,795	$105,541
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$328,933	95.6891%	$314,753	$24,212	$290,542
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$758,055	95.0081%	$720,214	$55,401	$664,813
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$528,529	95.2778%	$503,571	$38,736	$464,834
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$365,262	90.2300%	$329,576	$25,352	$304,224
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$263,790	100.0000%	$263,790	$20,292	$243,498
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$10,695	96.9888%	$10,373	$798	$9,575
24 - Manatee Reburn	Peaking	$2,865,912	95.2778%	$2,730,577	$2,730,577	$0
26 - UST Remove/Replacement	General	$6,545	96.9888%	$6,348	$488	$5,860
28 - CWA 316(b) Phase II Rule	Intermediate	$76,528	95.0081%	$72,707	$5,593	$67,115
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$35,751,649	95.6891%	$34,210,424	$2,631,571	$31,578,853
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$111,620	95.0081%	$106,048	$8,158	$97,890
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$8,647,795	95.2778%	$8,239,427	$633,802	$7,605,624
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$101	100.0000%	$101	$8	$93
33 - MATS Project	Base	$9,252,605	95.6891%	$8,853,732	$681,056	$8,172,676
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$357,304	95.6891%	$341,901	$26,300	$315,601
35 - Martin Plant Drinking Water System Compliance	Intermediate	$11,290	95.0081%	$10,726	$825	$9,901
35 - Martin Plant Drinking Water System Compliance	Peaking	$8,517	95.2778%	$8,115	$624	$7,491
36 - Low-Level Radioactive Waste Storage	Base	$1,622,516	95.6891%	$1,552,571	$119,429	$1,433,142
37 - DeSoto Next Generation Solar Energy Center	Solar	$11,450,670	95.6891%	$10,957,041	$842,849	$10,114,191
38 - Space Coast Next Generation Solar Energy Center	Solar	$5,342,024	95.6891%	$5,111,733	$393,210	$4,718,523
39 - Martin Next Generation Solar Energy Center	Intermediate	$33,133,292	95.0081%	$31,479,322	$2,421,486	$29,057,835
41 - Manatee Temporary Heating System	Intermediate	$3,152,890	95.0081%	$2,995,502	$230,423	$2,765,079
41 - Manatee Temporary Heating System	Distribution	$18,284	100.0000%	$18,284	$1,406	$16,877
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$5,299,641	95.6891%	$5,071,178	$390,091	$4,681,087
42 - Turkey Point Cooling Canal Monitoring Plan	Intermediate	$1,508,083	95.0081%	$1,432,801	$110,215	$1,322,586
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$8,175	95.0081%	$7,767	$0	$7,767
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$6,167	95.2778%	$5,876	$0	$5,876
45 - 800 MW Unit ESP	Intermediate	$8,069	95.0081%	$7,667	$0	$7,667
45 - 800 MW Unit ESP	Peaking	$18,492,026	95.2778%	$17,618,790	$0	$17,618,790
47 - NPDES Permit Renewal Requirements	Base	$301,421	95.6891%	$288,427	$0	$288,427
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$385,191	95.6891%	$368,586	$28,353	$340,233
54 - Coal Combustion Residuals	Base	$11,297,162	95.6891%	$10,810,150	$831,550	$9,978,600
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($15)	95.6891%	($14)	($14)	$0
123 - Protected Species Project	Intermediate	$7,364	95.0081%	$6,996	$0	$6,996
	Total	$154,788,070		$147,717,804	$12,942,264	$134,775,540

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-3P

JANUARY 2021 THROUGH DECEMBER 2021

CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Total
2. Total of Capital Investment Projects	$12,971,942	$12,957,772	$12,940,454	$12,923,407	$12,906,366	$12,893,887	$12,882,262	$12,867,275	$12,861,177	$12,858,127	$12,849,765	$12,875,635	$154,788,070
3. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$30,684	$30,639	$30,595	$30,550	$30,505	$30,461	$30,416	$30,372	$30,327	$30,282	$30,238	$30,193	$365,262
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$5,425,196	$5,428,570	$5,429,602	$5,430,884	$5,432,318	$5,437,982	$5,442,852	$5,444,368	$5,455,335	$5,468,939	$5,477,378	$5,517,595	$65,391,018
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$3,335,070	$3,327,740	$3,319,741	$3,311,756	$3,303,642	$3,295,674	$3,289,178	$3,282,668	$3,275,595	$3,268,722	$3,260,923	$3,256,011	$39,526,720
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$2,670,313	$2,664,442	$2,658,835	$2,653,238	$2,647,621	$2,642,191	$2,636,937	$2,631,673	$2,626,409	$2,621,400	$2,616,202	$2,610,546	$31,679,808
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$1,424,049	$1,419,856	$1,415,262	$1,410,667	$1,406,073	$1,401,479	$1,396,884	$1,392,307	$1,387,729	$1,383,107	$1,379,454	$1,375,827	$16,792,694
Recoverable Costs Jurisdicitionalized on 12 CP Demand - General	$62,902	$62,831	$62,760	$62,688	$62,617	$62,546	$62,475	$62,404	$62,333	$62,262	$62,191	$62,120	$750,131
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$23,729	$23,694	$23,659	$23,624	$23,589	$23,554	$23,519	$23,484	$23,449	$23,414	$23,379	$23,344	$282,437
4. Retail Transmission Demand Jurisdictional Factor	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	90.22999%	
Retail Production Demand Jurisdictional Factor - Base	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	
Retail Production Demand Jurisdictional Factor - Intermediate	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	
Retail Production Demand Jurisdictional Factor - Peaking	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	
Retail Production Demand Jurisdictional Factor - Solar	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	
Retail Production Demand Jurisdictional Factor - General	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	
Retail Distribution Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
5. Jurisdictional Recoverable Costs - Transmission	$27,686	$27,646	$27,606	$27,565	$27,525	$27,485	$27,445	$27,404	$27,364	$27,324	$27,284	$27,243	$329,576
Jurisdictional Recoverable Costs - Production - Base	$5,191,320	$5,194,548	$5,195,536	$5,196,762	$5,198,135	$5,203,555	$5,208,215	$5,209,666	$5,220,160	$5,233,177	$5,241,252	$5,279,735	$62,572,062
Jurisdictional Recoverable Costs - Production - Intermediate	$3,168,588	$3,161,623	$3,154,024	$3,146,437	$3,138,728	$3,131,159	$3,124,987	$3,118,801	$3,112,082	$3,105,552	$3,098,142	$3,093,475	$37,553,597
Jurisdictional Recoverable Costs - Production - Peaking	$2,544,214	$2,538,621	$2,533,279	$2,527,946	$2,522,595	$2,517,421	$2,512,415	$2,507,399	$2,502,384	$2,497,612	$2,492,659	$2,487,270	$30,183,815
Jurisdictional Recoverable Costs - Production - Solar	$1,362,659	$1,358,648	$1,354,251	$1,349,855	$1,345,458	$1,341,062	$1,336,665	$1,332,285	$1,327,905	$1,323,482	$1,319,987	$1,316,516	$16,068,774
Jurisdictional Recoverable Costs - General	$61,007	$60,939	$60,870	$60,801	$60,732	$60,663	$60,594	$60,525	$60,456	$60,387	$60,319	$60,250	$727,543
Jurisdictional Recoverable Costs - Distribution	$23,729	$23,694	$23,659	$23,624	$23,589	$23,554	$23,519	$23,484	$23,449	$23,414	$23,379	$23,344	$282,437
6. Total Jurisdictional Recoverable Costs for Capital Investment Activities	$12,379,204	$12,365,719	$12,349,224	$12,332,991	$12,316,762	$12,304,898	$12,293,840	$12,279,565	$12,273,799	$12,270,948	$12,263,021	$12,287,833	$147,717,804

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
02 - Low NOX Burner Technology														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3a. Less: Accumulated Depreciation	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
3b. Less: Capital Recovery Unamortized Balance	($225,496)	($222,364)	($219,233)	($216,101)	($212,969)	($209,837)	($206,705)	($203,573)	($200,441)	($197,309)	($194,177)	($191,045)	($187,914)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$225,497	$222,365	$219,233	$216,101	$212,969	$209,837	$206,705	$203,573	$200,441	$197,310	$194,178	$191,046	$187,914	
6. Average Net Investment		$223,931	$220,799	$217,667	$214,535	$211,403	$208,271	$205,139	$202,007	$198,876	$195,744	$192,612	$189,480	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,267	$1,249	$1,231	$1,214	$1,196	$1,178	$1,161	$1,143	$1,125	$1,107	$1,090	$1,072	$14,033
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$232	$228	$225	$222	$219	$215	$212	$209	$206	$202	$199	$196	$2,564
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$37,583
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$4,630	$4,609	$4,588	$4,567	$4,546	$4,526	$4,505	$4,484	$4,463	$4,442	$4,421	$4,400	$54,180

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
03 - Continuous Emission Monitoring Systems														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	$515,653	
3a. Less: Accumulated Depreciation	$419,486	$420,685	$421,884	$423,083	$424,282	$425,481	$426,680	$427,879	$429,078	$430,276	$431,475	$432,674	$433,873	
3b. Less: Capital Recovery Unamortized Balance	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	($62,603)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$158,770	$157,571	$156,372	$155,173	$153,974	$152,775	$151,576	$150,377	$149,179	$147,980	$146,781	$145,582	$144,383	
6. Average Net Investment		$158,170	$156,971	$155,772	$154,574	$153,375	$152,176	$150,977	$149,778	$148,579	$147,380	$146,181	$144,982	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$895	$888	$881	$874	$868	$861	$854	$847	$841	$834	$827	$820	$10,290
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$164	$162	$161	$160	$159	$157	$156	$155	$154	$152	$151	$150	$1,880
8. Investment Expenses														
a. Depreciation (e)		$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$14,387
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,257	$2,249	$2,241	$2,233	$2,225	$2,217	$2,209	$2,201	$2,193	$2,185	$2,177	$2,169	$26,558

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
03 - Continuous Emission Monitoring Systems														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($54,148)	($2,240)	$4,359	$114	$0	$0	$0	$0	$0	$0	$0	($2,993)	($54,908)
c. Retirements		($54,148)	($2,240)	$4,359	$114	$0	$0	$0	$0	$0	$0	$0	($2,993)	($54,908)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,285,694	$2,231,547	$2,229,306	$2,233,665	$2,233,779	$2,233,779	$2,233,779	$2,233,779	$2,233,779	$2,233,779	$2,233,779	$2,233,779	$2,230,786	
3a. Less: Accumulated Depreciation	$609,830	$563,005	$567,789	$579,185	$586,363	$593,427	$600,492	$607,557	$614,621	$621,686	$628,751	$635,815	$639,869	
3b. Less: Capital Recovery Unamortized Balance	($174,048)	($171,630)	($169,213)	($166,796)	($164,378)	($161,961)	($159,544)	($157,126)	($154,709)	($152,292)	($149,874)	($147,457)	($145,040)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,849,911	$1,840,172	$1,830,730	$1,821,275	$1,811,794	$1,802,312	$1,792,830	$1,783,348	$1,773,866	$1,764,384	$1,754,902	$1,745,421	$1,735,956	
6. Average Net Investment		$1,845,042	$1,835,451	$1,826,003	$1,816,535	$1,807,053	$1,797,571	$1,788,089	$1,778,607	$1,769,125	$1,759,643	$1,750,162	$1,740,688	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$10,438	$10,384	$10,331	$10,277	$10,223	$10,170	$10,116	$10,062	$10,009	$9,955	$9,902	$9,848	$121,715
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,907	$1,898	$1,888	$1,878	$1,868	$1,858	$1,849	$1,839	$1,829	$1,819	$1,809	$1,800	$22,242
8. Investment Expenses														
a. Depreciation (e)		$7,322	$7,025	$7,037	$7,064	$7,065	$7,065	$7,065	$7,065	$7,065	$7,065	$7,065	$7,047	$84,947
b. Amortization (f)		$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$29,008
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$22,085	$21,724	$21,673	$21,636	$21,574	$21,510	$21,447	$21,383	$21,320	$21,256	$21,193	$21,112	$257,912

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
03 - Continuous Emission Monitoring Systems														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	$1,201,724	
3a. Less: Accumulated Depreciation	$231,312	$235,849	$240,385	$244,922	$249,458	$253,995	$258,532	$263,068	$267,605	$272,141	$276,678	$281,214	$285,751	
3b. Less: Capital Recovery Unamortized Balance	($126,397)	($124,642)	($122,886)	($121,130)	($119,375)	($117,619)	($115,864)	($114,108)	($112,353)	($110,597)	($108,842)	($107,086)	($105,331)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,096,808	$1,090,516	$1,084,224	$1,077,932	$1,071,640	$1,065,348	$1,059,056	$1,052,764	$1,046,472	$1,040,180	$1,033,888	$1,027,596	$1,021,304	
6. Average Net Investment		$1,093,662	$1,087,370	$1,081,078	$1,074,786	$1,068,494	$1,062,202	$1,055,910	$1,049,618	$1,043,326	$1,037,034	$1,030,742	$1,024,450	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,187	$6,152	$6,116	$6,081	$6,045	$6,009	$5,974	$5,938	$5,903	$5,867	$5,831	$5,796	$71,899
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,131	$1,124	$1,118	$1,111	$1,105	$1,098	$1,092	$1,085	$1,079	$1,072	$1,066	$1,059	$13,139
8. Investment Expenses														
a. Depreciation (e)		$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$4,537	$54,439
b. Amortization (f)		$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$21,066
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$13,610	$13,568	$13,526	$13,484	$13,442	$13,400	$13,358	$13,315	$13,273	$13,231	$13,189	$13,147	$160,543

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3b. Less: Capital Recovery Unamortized Balance	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	($22,529)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	
6. Average Net Investment		$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	$22,529	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$127	$127	$127	$127	$127	$127	$127	$127	$127	$127	$127	$127	$1,530
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$23	$23	$23	$23	$23	$23	$23	$23	$23	$23	$23	$23	$279
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$151	$151	$151	$151	$151	$151	$151	$151	$151	$151	$151	$151	$1,809

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	$8,224,667	
3a. Less: Accumulated Depreciation	$576,112	$586,393	$596,674	$606,955	$617,236	$627,516	$637,797	$648,078	$658,359	$668,640	$678,921	$689,201	$699,482	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,648,554	$7,638,274	$7,627,993	$7,617,712	$7,607,431	$7,597,150	$7,586,869	$7,576,589	$7,566,308	$7,556,027	$7,545,746	$7,535,465	$7,525,184	
6. Average Net Investment		$7,643,414	$7,633,133	$7,622,852	$7,612,571	$7,602,291	$7,592,010	$7,581,729	$7,571,448	$7,561,167	$7,550,886	$7,540,606	$7,530,325	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$43,242	$43,184	$43,126	$43,068	$43,010	$42,952	$42,894	$42,835	$42,777	$42,719	$42,661	$42,603	$515,071
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$7,902	$7,891	$7,881	$7,870	$7,860	$7,849	$7,838	$7,828	$7,817	$7,806	$7,796	$7,785	$94,123
8. Investment Expenses														
a. Depreciation (e)		$10,281	$10,281	$10,281	$10,281	$10,281	$10,281	$10,281	$10,281	$10,281	$10,281	$10,281	$10,281	$123,370
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$61,425	$61,357	$61,288	$61,219	$61,150	$61,081	$61,013	$60,944	$60,875	$60,806	$60,737	$60,669	$732,564

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	$2,290,632	
3a. Less: Accumulated Depreciation	$1,118,463	$1,124,430	$1,130,397	$1,136,364	$1,142,331	$1,148,298	$1,154,265	$1,160,232	$1,166,199	$1,172,167	$1,178,134	$1,184,101	$1,190,068	
3b. Less: Capital Recovery Unamortized Balance	($222,605)	($219,504)	($216,403)	($213,302)	($210,201)	($207,100)	($203,999)	($200,899)	($197,798)	($194,697)	($191,596)	($188,495)	($185,394)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,394,775	$1,385,707	$1,376,639	$1,367,571	$1,358,503	$1,349,434	$1,340,366	$1,331,298	$1,322,230	$1,313,162	$1,304,094	$1,295,026	$1,285,958	
6. Average Net Investment		$1,390,241	$1,381,173	$1,372,105	$1,363,037	$1,353,968	$1,344,900	$1,335,832	$1,326,764	$1,317,696	$1,308,628	$1,299,560	$1,290,492	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$7,865	$7,814	$7,763	$7,711	$7,660	$7,609	$7,557	$7,506	$7,455	$7,404	$7,352	$7,301	$90,997
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,437	$1,428	$1,419	$1,409	$1,400	$1,390	$1,381	$1,372	$1,362	$1,353	$1,344	$1,334	$16,629
8. Investment Expenses														
a. Depreciation (e)		$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$5,967	$71,605
b. Amortization (f)		$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$3,101	$37,212
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$18,371	$18,310	$18,249	$18,189	$18,128	$18,067	$18,007	$17,946	$17,885	$17,825	$17,764	$17,703	$216,443

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	$3,516,550	
3a. Less: Accumulated Depreciation	$1,595,708	$1,606,883	$1,618,059	$1,629,234	$1,640,409	$1,651,585	$1,662,760	$1,673,936	$1,685,111	$1,696,287	$1,707,462	$1,718,637	$1,729,813	
3b. Less: Capital Recovery Unamortized Balance	($1,671,358)	($1,648,156)	($1,624,953)	($1,601,750)	($1,578,547)	($1,555,344)	($1,532,142)	($1,508,939)	($1,485,736)	($1,462,533)	($1,439,330)	($1,416,127)	($1,392,925)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,592,201	$3,557,823	$3,523,445	$3,489,066	$3,454,688	$3,420,310	$3,385,932	$3,351,553	$3,317,175	$3,282,797	$3,248,419	$3,214,040	$3,179,662	
6. Average Net Investment		$3,575,012	$3,540,634	$3,506,255	$3,471,877	$3,437,499	$3,403,121	$3,368,742	$3,334,364	$3,299,986	$3,265,608	$3,231,229	$3,196,851	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$20,226	$20,031	$19,837	$19,642	$19,448	$19,253	$19,059	$18,864	$18,670	$18,475	$18,281	$18,086	$229,870
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3,696	$3,660	$3,625	$3,589	$3,554	$3,518	$3,483	$3,447	$3,412	$3,376	$3,341	$3,305	$42,006
8. Investment Expenses														
a. Depreciation (e)		$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$11,175	$134,105
b. Amortization (f)		$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$23,203	$278,434
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$58,300	$58,070	$57,840	$57,610	$57,380	$57,150	$56,920	$56,690	$56,460	$56,229	$55,999	$55,769	$684,415

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	$31,030	
3a. Less: Accumulated Depreciation	$32,454	$32,587	$32,719	$32,851	$32,983	$33,115	$33,247	$33,379	$33,512	$33,644	$33,776	$33,908	$34,040	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	($1,424)	($1,557)	($1,689)	($1,821)	($1,953)	($2,085)	($2,217)	($2,349)	($2,482)	($2,614)	($2,746)	($2,878)	($3,010)	
6. Average Net Investment		($1,491)	($1,623)	($1,755)	($1,887)	($2,019)	($2,151)	($2,283)	($2,416)	($2,548)	($2,680)	($2,812)	($2,944)	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		($8)	($9)	($10)	($11)	($11)	($12)	($13)	($14)	($14)	($15)	($16)	($17)	($151)
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	($28)
8. Investment Expenses														
a. Depreciation (e)		$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$1,586
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$122	$121	$120	$120	$119	$118	$117	$116	$115	$114	$113	$112	$1,408

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	$2,995	
3a. Less: Accumulated Depreciation	$449	$453	$458	$463	$468	$473	$478	$483	$488	$493	$498	$503	$508	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,547	$2,542	$2,537	$2,532	$2,527	$2,522	$2,517	$2,512	$2,507	$2,502	$2,497	$2,492	$2,487	
6. Average Net Investment		$2,544	$2,539	$2,534	$2,529	$2,524	$2,519	$2,514	$2,509	$2,504	$2,499	$2,494	$2,489	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14	$171
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$31
8. Investment Expenses														
a. Depreciation (e)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$60
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$262

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	
3a. Less: Accumulated Depreciation	$1,136	$1,141	$1,147	$1,152	$1,158	$1,163	$1,169	$1,174	$1,180	$1,185	$1,191	$1,196	$1,202	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,277	$3,272	$3,266	$3,261	$3,255	$3,250	$3,244	$3,239	$3,233	$3,227	$3,222	$3,216	$3,211	
6. Average Net Investment		$3,274	$3,269	$3,263	$3,258	$3,252	$3,247	$3,241	$3,236	$3,230	$3,225	$3,219	$3,214	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$19	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$220
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$40
8. Investment Expenses														
a. Depreciation (e)		$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$66
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$327

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
08 - Oil Spill Clean-up/Response Equipment														
Intermediate														
1. Investments														
a. Expenditures/Additions		$3,142	$3,142	$3,142	$3,142	$3,142	$3,142	$1,954	$1,954	$1,954	$1,954	$1,954	$1,954	$30,573
b. Clearings to Plant		$3,142	$3,142	$3,142	$3,142	$3,142	$3,142	$1,954	$1,954	$1,954	$1,954	$1,954	$1,954	$30,573
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$920,687	$923,829	$926,970	$930,112	$933,253	$936,395	$939,536	$941,490	$943,444	$945,398	$947,352	$949,306	$951,261	
3a. Less: Accumulated Depreciation	$42,486	$48,008	$53,582	$59,208	$64,887	$70,618	$76,402	$82,227	$88,086	$93,977	$99,900	$105,857	$111,845	
3b. Less: Capital Recovery Unamortized Balance	$132	$130	$128	$126	$125	$123	$121	$119	$117	$115	$114	$112	$110	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$878,069	$875,691	$873,260	$870,777	$868,242	$865,654	$863,014	$859,144	$855,241	$851,306	$847,338	$843,338	$839,305	
6. Average Net Investment		$876,880	$874,475	$872,018	$869,509	$866,948	$864,334	$861,079	$857,193	$853,274	$849,322	$845,338	$841,322	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$4,961	$4,947	$4,933	$4,919	$4,905	$4,890	$4,872	$4,850	$4,827	$4,805	$4,782	$4,760	$58,451
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$907	$904	$902	$899	$896	$894	$890	$886	$882	$878	$874	$870	$10,681
8. Investment Expenses														
a. Depreciation (e)		$5,522	$5,574	$5,626	$5,679	$5,731	$5,783	$5,826	$5,858	$5,891	$5,924	$5,956	$5,989	$69,359
b. Amortization (f)		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($22)
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$11,387	$11,424	$11,459	$11,495	$11,530	$11,565	$11,586	$11,592	$11,599	$11,605	$11,611	$11,616	$138,469

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

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08 - Oil Spill Clean-up/Response Equipment														
Peaking														
1. Investments														
a. Expenditures/Additions		$2,370	$2,370	$2,370	$2,370	$2,370	$2,370	$1,474	$1,474	$1,474	$1,474	$1,474	$1,474	$23,064
b. Clearings to Plant		($38,478)	$680	$5,658	$2,456	$2,370	$2,370	$1,474	$1,474	$1,474	$1,474	$1,474	($784)	($18,358)
c. Retirements		($40,848)	($1,690)	$3,288	$86	$0	$0	$0	$0	$0	$0	$0	($2,258)	($41,422)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$503,382	$464,903	$465,583	$471,241	$473,697	$476,067	$478,437	$479,911	$481,385	$482,859	$484,333	$485,808	$485,024	
3a. Less: Accumulated Depreciation	$154,511	$117,146	$118,727	$125,334	$128,799	$132,218	$135,677	$139,167	$142,682	$146,222	$149,786	$153,375	$154,717	
4. CWIP	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$348,871	$347,757	$346,857	$345,907	$344,898	$343,849	$342,760	$340,744	$338,703	$336,637	$334,547	$332,433	$330,307	
6. Average Net Investment		$348,314	$347,307	$346,382	$345,403	$344,374	$343,305	$341,752	$339,724	$337,670	$335,592	$333,490	$331,370	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,971	$1,965	$1,960	$1,954	$1,948	$1,942	$1,933	$1,922	$1,910	$1,899	$1,887	$1,875	$23,166
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$360	$359	$358	$357	$356	$355	$353	$351	$349	$347	$345	$343	$4,233
8. Investment Expenses														
a. Depreciation (e)		$3,484	$3,270	$3,319	$3,379	$3,419	$3,458	$3,491	$3,515	$3,540	$3,564	$3,589	$3,600	$41,629
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$5,815	$5,594	$5,637	$5,690	$5,723	$5,756	$5,777	$5,788	$5,799	$5,810	$5,820	$5,817	$69,027

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
10 - Relocate Storm Water Runoff														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	
3a. Less: Accumulated Depreciation	$74,429	$74,649	$74,870	$75,091	$75,312	$75,533	$75,754	$75,975	$76,195	$76,416	$76,637	$76,858	$77,079	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$43,365	$43,144	$42,924	$42,703	$42,482	$42,261	$42,040	$41,819	$41,598	$41,378	$41,157	$40,936	$40,715	
6. Average Net Investment		$43,255	$43,034	$42,813	$42,592	$42,371	$42,151	$41,930	$41,709	$41,488	$41,267	$41,046	$40,825	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$245	$243	$242	$241	$240	$238	$237	$236	$235	$233	$232	$231	$2,854
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$45	$44	$44	$44	$44	$44	$43	$43	$43	$43	$42	$42	$522
8. Investment Expenses														
a. Depreciation (e)		$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$2,650
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$510	$509	$507	$506	$504	$503	$501	$500	$498	$497	$496	$494	$6,026

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
12 - Scherer Discharge Pipeline														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	$854,324	
3a. Less: Accumulated Depreciation	$630,300	$631,573	$632,846	$634,118	$635,391	$636,663	$637,936	$639,209	$640,481	$641,754	$643,026	$644,299	$645,572	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$224,023	$222,751	$221,478	$220,205	$218,933	$217,660	$216,388	$215,115	$213,842	$212,570	$211,297	$210,025	$208,752	
6. Average Net Investment		$223,387	$222,114	$220,842	$219,569	$218,297	$217,024	$215,751	$214,479	$213,206	$211,934	$210,661	$209,388	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,264	$1,257	$1,249	$1,242	$1,235	$1,228	$1,221	$1,213	$1,206	$1,199	$1,192	$1,185	$14,691
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$231	$230	$228	$227	$226	$224	$223	$222	$220	$219	$218	$216	$2,685
8. Investment Expenses														
a. Depreciation (e)		$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$15,271
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,767	$2,759	$2,750	$2,742	$2,733	$2,725	$2,716	$2,708	$2,699	$2,691	$2,682	$2,674	$32,646

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
20 - Wastewater Discharge Elimination & Reuse														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3a. Less: Accumulated Depreciation	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	($531,712)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	
6. Average Net Investment		$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	$531,712	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$3,008	$3,008	$3,008	$3,008	$3,008	$3,008	$3,008	$3,008	$3,008	$3,008	$3,008	$3,008	$36,098
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$550	$550	$550	$550	$550	$550	$550	$550	$550	$550	$550	$550	$6,596
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$3,558	$42,694

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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21 - St. Lucie Turtle Nets														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	
3a. Less: Accumulated Depreciation	($275,611)	($262,656)	($249,700)	($236,745)	($223,789)	($210,834)	($197,879)	($184,923)	($171,968)	($159,012)	($146,057)	($133,101)	($120,146)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,185,170	$7,172,214	$7,159,259	$7,146,303	$7,133,348	$7,120,393	$7,107,437	$7,094,482	$7,081,526	$7,068,571	$7,055,615	$7,042,660	$7,029,705	
6. Average Net Investment		$7,178,692	$7,165,737	$7,152,781	$7,139,826	$7,126,870	$7,113,915	$7,100,959	$7,088,004	$7,075,049	$7,062,093	$7,049,138	$7,036,182	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$40,613	$40,540	$40,467	$40,393	$40,320	$40,247	$40,174	$40,100	$40,027	$39,954	$39,880	$39,807	$482,523
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$7,422	$7,408	$7,395	$7,381	$7,368	$7,355	$7,341	$7,328	$7,314	$7,301	$7,288	$7,274	$88,175
8. Investment Expenses														
a. Depreciation (e)		$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$155,465
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$60,990	$60,904	$60,817	$60,730	$60,644	$60,557	$60,470	$60,384	$60,297	$60,210	$60,123	$60,037	$726,163

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

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22 - Pipeline Integrity Management														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	$1,544,262	
3a. Less: Accumulated Depreciation	$303,596	$306,974	$310,352	$313,730	$317,108	$320,486	$323,864	$327,242	$330,620	$333,998	$337,376	$340,754	$344,132	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,240,666	$1,237,288	$1,233,910	$1,230,532	$1,227,154	$1,223,776	$1,220,398	$1,217,019	$1,213,641	$1,210,263	$1,206,885	$1,203,507	$1,200,129	
6. Average Net Investment		$1,238,977	$1,235,599	$1,232,221	$1,228,843	$1,225,465	$1,222,087	$1,218,709	$1,215,330	$1,211,952	$1,208,574	$1,205,196	$1,201,818	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$7,009	$6,990	$6,971	$6,952	$6,933	$6,914	$6,895	$6,876	$6,857	$6,837	$6,818	$6,799	$82,853
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,281	$1,277	$1,274	$1,270	$1,267	$1,263	$1,260	$1,256	$1,253	$1,249	$1,246	$1,242	$15,140
8. Investment Expenses														
a. Depreciation (e)		$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$3,378	$40,537
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$11,668	$11,646	$11,623	$11,601	$11,578	$11,555	$11,533	$11,510	$11,488	$11,465	$11,442	$11,420	$138,530

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
22 - Pipeline Integrity Management														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	$1,328,530	
3a. Less: Accumulated Depreciation	$261,561	$264,542	$267,522	$270,503	$273,483	$276,464	$279,444	$282,425	$285,405	$288,385	$291,366	$294,346	$297,327	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,066,968	$1,063,988	$1,061,007	$1,058,027	$1,055,047	$1,052,066	$1,049,086	$1,046,105	$1,043,125	$1,040,144	$1,037,164	$1,034,183	$1,031,203	
6. Average Net Investment		$1,065,478	$1,062,498	$1,059,517	$1,056,537	$1,053,556	$1,050,576	$1,047,595	$1,044,615	$1,041,635	$1,038,654	$1,035,674	$1,032,693	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,028	$6,011	$5,994	$5,977	$5,960	$5,944	$5,927	$5,910	$5,893	$5,876	$5,859	$5,842	$71,222
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,102	$1,098	$1,095	$1,092	$1,089	$1,086	$1,083	$1,080	$1,077	$1,074	$1,071	$1,068	$13,015
8. Investment Expenses														
a. Depreciation (e)		$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$2,980	$35,765
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$10,110	$10,090	$10,070	$10,050	$10,030	$10,010	$9,990	$9,970	$9,950	$9,930	$9,910	$9,891	$120,002

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	$3,245,435	
3a. Less: Accumulated Depreciation	$913,437	$925,738	$938,039	$950,340	$962,640	$974,941	$987,242	$999,543	$1,011,844	$1,024,145	$1,036,445	$1,048,746	$1,061,047	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,331,998	$2,319,697	$2,307,396	$2,295,095	$2,282,794	$2,270,493	$2,258,193	$2,245,892	$2,233,591	$2,221,290	$2,208,989	$2,196,688	$2,184,387	
6. Average Net Investment		$2,325,847	$2,313,546	$2,301,245	$2,288,945	$2,276,644	$2,264,343	$2,252,042	$2,239,741	$2,227,440	$2,215,140	$2,202,839	$2,190,538	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$13,158	$13,089	$13,019	$12,950	$12,880	$12,810	$12,741	$12,671	$12,602	$12,532	$12,463	$12,393	$153,308
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,405	$2,392	$2,379	$2,366	$2,354	$2,341	$2,328	$2,316	$2,303	$2,290	$2,277	$2,265	$28,015
8. Investment Expenses														
a. Depreciation (e)		$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$12,301	$147,610
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$27,864	$27,782	$27,699	$27,617	$27,535	$27,452	$27,370	$27,288	$27,205	$27,123	$27,041	$26,958	$328,933

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,577,045	$3,577,045	$3,577,045	$3,577,045	$3,577,045	$3,577,045	$3,577,045	$3,577,045	$3,577,045	$3,577,045	$3,577,045	$3,577,045	$3,577,045	
3a. Less: Accumulated Depreciation	$1,042,220	$1,047,451	$1,052,683	$1,057,914	$1,063,145	$1,068,376	$1,073,607	$1,078,839	$1,084,070	$1,089,301	$1,094,532	$1,099,763	$1,104,995	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,534,825	$2,529,594	$2,524,362	$2,519,131	$2,513,900	$2,508,669	$2,503,438	$2,498,206	$2,492,975	$2,487,744	$2,482,513	$2,477,282	$2,472,050	
6. Average Net Investment		$2,532,209	$2,526,978	$2,521,747	$2,516,516	$2,511,284	$2,506,053	$2,500,822	$2,495,591	$2,490,360	$2,485,128	$2,479,897	$2,474,666	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$14,326	$14,296	$14,267	$14,237	$14,208	$14,178	$14,148	$14,119	$14,089	$14,060	$14,030	$14,000	$169,958
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,618	$2,612	$2,607	$2,602	$2,596	$2,591	$2,585	$2,580	$2,575	$2,569	$2,564	$2,558	$31,058
8. Investment Expenses														
a. Depreciation (e)		$5,231	$5,231	$5,231	$5,231	$5,231	$5,231	$5,231	$5,231	$5,231	$5,231	$5,231	$5,231	$62,774
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$22,175	$22,140	$22,105	$22,070	$22,035	$22,000	$21,965	$21,930	$21,895	$21,860	$21,825	$21,790	$263,790

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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23 - SPCC - Spill Prevention, Control & Countermeasures														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	$146,691	
3a. Less: Accumulated Depreciation	$39,793	$39,977	$40,160	$40,343	$40,527	$40,710	$40,893	$41,077	$41,260	$41,443	$41,627	$41,810	$41,993	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$106,898	$106,715	$106,531	$106,348	$106,165	$105,981	$105,798	$105,615	$105,431	$105,248	$105,065	$104,881	$104,698	
6. Average Net Investment		$106,806	$106,623	$106,440	$106,256	$106,073	$105,890	$105,706	$105,523	$105,340	$105,156	$104,973	$104,790	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$604	$603	$602	$601	$600	$599	$598	$597	$596	$595	$594	$593	$7,183
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$110	$110	$110	$110	$110	$109	$109	$109	$109	$109	$109	$108	$1,313
8. Investment Expenses														
a. Depreciation (e)		$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$2,200
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$898	$897	$896	$894	$893	$892	$891	$889	$888	$887	$886	$885	$10,695

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

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23 - SPCC - Spill Prevention, Control & Countermeasures														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$43,987	$43,987	$43,987	$43,987	$44,054	$0	$0	$220,000
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$220,000	$0	$0	$220,000
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$6,252,366	$6,252,366	$6,252,366	$6,252,366	$6,252,366	$6,252,366	$6,252,366	$6,252,366	$6,252,366	$6,252,366	$6,472,366	$6,472,366	$6,472,366	
3a. Less: Accumulated Depreciation	$922,793	$937,236	$951,679	$966,122	$980,565	$995,008	$1,009,451	$1,023,894	$1,038,336	$1,052,779	$1,067,424	$1,082,270	$1,097,117	
3b. Less: Capital Recovery Unamortized Balance	($761,081)	($750,466)	($739,852)	($729,237)	($718,623)	($708,009)	($697,394)	($686,780)	($676,166)	($665,551)	($654,937)	($644,323)	($633,708)	
4. CWIP	($339,221)	($339,221)	($339,221)	($339,221)	($339,221)	($339,221)	($295,235)	($251,248)	($207,262)	($163,275)	($339,221)	($339,221)	($339,221)	
5. Net Investment (Lines 2 - 3 + 4)	$5,751,432	$5,726,375	$5,701,318	$5,676,260	$5,651,203	$5,626,146	$5,645,075	$5,664,004	$5,682,933	$5,701,863	$5,720,657	$5,695,197	$5,669,736	
6. Average Net Investment		$5,738,904	$5,713,846	$5,688,789	$5,663,732	$5,638,674	$5,635,610	$5,654,540	$5,673,469	$5,692,398	$5,711,260	$5,707,927	$5,682,466	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$32,468	$32,326	$32,184	$32,042	$31,901	$31,883	$31,990	$32,098	$32,205	$32,311	$32,293	$32,148	$385,850
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$5,933	$5,907	$5,881	$5,855	$5,829	$5,826	$5,846	$5,865	$5,885	$5,904	$5,901	$5,875	$70,509
8. Investment Expenses														
a. Depreciation (e)		$14,443	$14,443	$14,443	$14,443	$14,443	$14,443	$14,443	$14,443	$14,443	$14,645	$14,846	$14,846	$174,324
b. Amortization (f)		$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$10,614	$127,372
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$63,458	$63,290	$63,123	$62,955	$62,787	$62,767	$62,894	$63,020	$63,147	$63,475	$63,654	$63,484	$758,055

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$55,983	$55,983	$55,983	$55,983	$56,068	$0	$0	$280,000
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$280,000	$0	$0	$280,000
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,078,932	$3,358,932	$3,358,932	$3,358,932	
3a. Less: Accumulated Depreciation	$1,446,083	$1,457,784	$1,469,486	$1,481,188	$1,492,890	$1,504,592	$1,516,294	$1,527,996	$1,539,698	$1,551,400	$1,563,359	$1,575,574	$1,587,789	
3b. Less: Capital Recovery Unamortized Balance	($941,423)	($928,391)	($915,360)	($902,328)	($889,297)	($876,265)	($863,234)	($850,202)	($837,171)	($824,139)	($811,108)	($798,076)	($785,045)	
4. CWIP	$339,221	$339,221	$339,221	$339,221	$339,221	$339,221	$395,204	$451,187	$507,170	$563,153	$339,221	$339,221	$339,221	
5. Net Investment (Lines 2 - 3 + 4)	$2,913,494	$2,888,760	$2,864,027	$2,839,293	$2,814,560	$2,789,827	$2,821,076	$2,852,325	$2,883,575	$2,914,824	$2,945,902	$2,920,655	$2,895,409	
6. Average Net Investment		$2,901,127	$2,876,394	$2,851,660	$2,826,927	$2,802,193	$2,805,451	$2,836,701	$2,867,950	$2,899,199	$2,930,363	$2,933,279	$2,908,032	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$16,413	$16,273	$16,133	$15,993	$15,853	$15,872	$16,049	$16,225	$16,402	$16,578	$16,595	$16,452	$194,840
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,999	$2,974	$2,948	$2,923	$2,897	$2,900	$2,933	$2,965	$2,997	$3,030	$3,033	$3,006	$35,604
8. Investment Expenses														
a. Depreciation (e)		$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,702	$11,959	$12,215	$12,215	$141,707
b. Amortization (f)		$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$13,032	$156,378
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$44,146	$43,980	$43,815	$43,649	$43,484	$43,506	$43,715	$43,924	$44,133	$44,598	$44,874	$44,705	$528,529

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
23 - SPCC - Spill Prevention, Control & Countermeasures														
Transmission														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	$4,118,132	
3a. Less: Accumulated Depreciation	$525,372	$532,038	$538,703	$545,369	$552,035	$558,701	$565,367	$572,033	$578,698	$585,364	$592,030	$598,696	$605,362	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,592,761	$3,586,095	$3,579,429	$3,572,763	$3,566,097	$3,559,432	$3,552,766	$3,546,100	$3,539,434	$3,532,768	$3,526,103	$3,519,437	$3,512,771	
6. Average Net Investment		$3,589,428	$3,582,762	$3,576,096	$3,569,430	$3,562,764	$3,556,099	$3,549,433	$3,542,767	$3,536,101	$3,529,435	$3,522,770	$3,516,104	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$20,307	$20,269	$20,232	$20,194	$20,156	$20,119	$20,081	$20,043	$20,005	$19,968	$19,930	$19,892	$241,197
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3,711	$3,704	$3,697	$3,690	$3,683	$3,676	$3,670	$3,663	$3,656	$3,649	$3,642	$3,635	$44,076
8. Investment Expenses														
a. Depreciation (e)		$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$6,666	$79,990
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$30,684	$30,639	$30,595	$30,550	$30,505	$30,461	$30,416	$30,372	$30,327	$30,282	$30,238	$30,193	$365,262

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
24 - Manatee Reburn														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	$31,863,719	
3a. Less: Accumulated Depreciation	$14,489,489	$14,617,185	$14,744,882	$14,872,578	$15,000,274	$15,127,970	$15,255,666	$15,383,363	$15,511,059	$15,638,755	$15,766,451	$15,894,147	$16,021,844	
4. CWIP	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$17,374,229	$17,246,533	$17,118,837	$16,991,141	$16,863,445	$16,735,748	$16,608,052	$16,480,356	$16,352,660	$16,224,964	$16,097,267	$15,969,571	$15,841,875	
6. Average Net Investment		$17,310,381	$17,182,685	$17,054,989	$16,927,293	$16,799,596	$16,671,900	$16,544,204	$16,416,508	$16,288,812	$16,161,115	$16,033,419	$15,905,723	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$97,933	$97,211	$96,488	$95,766	$95,043	$94,321	$93,599	$92,876	$92,154	$91,431	$90,709	$89,986	$1,127,518
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$17,896	$17,764	$17,632	$17,500	$17,368	$17,236	$17,104	$16,972	$16,840	$16,708	$16,576	$16,444	$206,039
8. Investment Expenses														
a. Depreciation (e)		$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$127,696	$1,532,354
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$243,525	$242,671	$241,817	$240,962	$240,108	$239,253	$238,399	$237,544	$236,690	$235,835	$234,981	$234,126	$2,865,912

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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26 - UST Remove/Replacement														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	
3a. Less: Accumulated Depreciation	$54,635	$54,779	$54,923	$55,068	$55,212	$55,356	$55,501	$55,645	$55,789	$55,933	$56,078	$56,222	$56,366	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$60,812	$60,668	$60,523	$60,379	$60,235	$60,090	$59,946	$59,802	$59,658	$59,513	$59,369	$59,225	$59,080	
6. Average Net Investment		$60,740	$60,596	$60,451	$60,307	$60,163	$60,018	$59,874	$59,730	$59,585	$59,441	$59,297	$59,152	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$344	$343	$342	$341	$340	$340	$339	$338	$337	$336	$335	$335	$4,070
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$63	$63	$62	$62	$62	$62	$62	$62	$62	$61	$61	$61	$744
8. Investment Expenses														
a. Depreciation (e)		$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,732
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$551	$550	$549	$548	$547	$546	$545	$544	$543	$542	$541	$540	$6,545

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
28 - CWA 316(b) Phase II Rule														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	$771,310	
3a. Less: Accumulated Depreciation	$66,264	$67,993	$69,722	$71,451	$73,180	$74,909	$76,638	$78,367	$80,096	$81,825	$83,554	$85,283	$87,012	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$705,047	$703,318	$701,589	$699,860	$698,131	$696,402	$694,673	$692,944	$691,215	$689,486	$687,757	$686,028	$684,299	
6. Average Net Investment		$704,182	$702,453	$700,724	$698,995	$697,266	$695,537	$693,808	$692,079	$690,350	$688,621	$686,892	$685,163	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$3,984	$3,974	$3,964	$3,955	$3,945	$3,935	$3,925	$3,915	$3,906	$3,896	$3,886	$3,876	$47,161
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$728	$726	$724	$723	$721	$719	$717	$715	$714	$712	$710	$708	$8,618
8. Investment Expenses														
a. Depreciation (e)		$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$1,729	$20,748
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$6,441	$6,429	$6,418	$6,406	$6,395	$6,383	$6,372	$6,360	$6,348	$6,337	$6,325	$6,314	$76,528

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
Base														
1. Investments														
a. Expenditures/Additions		$0	$99,917	$99,917	$99,917	$99,917	$99,917	$99,917	$99,917	$99,917	$99,917	$99,917	$199,834	$1,199,005
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,563,715	1,563,715
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$361,740,394	$361,740,394	$361,740,394	$361,740,394	$361,740,394	$361,740,394	$361,740,394	$361,740,394	$361,740,394	$361,740,394	$361,740,394	$361,740,394	$363,304,109	
3a. Less: Accumulated Depreciation	$75,556,375	$76,350,556	$77,150,883	$77,951,211	$78,751,539	$79,551,867	$80,352,195	$81,152,523	$81,952,850	$82,753,178	$83,553,506	$84,353,834	$85,155,673	
3b. Less: Capital Recovery Unamortized Balance	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	($43,439,531)	
4. CWIP	$364,710	$364,710	$464,627	$564,544	$664,461	$764,378	$864,296	$964,213	$1,064,130	$1,164,047	$1,263,964	$1,363,881	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$329,988,260	$329,194,079	$328,493,668	$327,793,258	$327,092,847	$326,392,436	$325,692,026	$324,991,615	$324,291,204	$323,590,794	$322,890,383	$322,189,972	$321,587,966	
6. Average Net Investment		$329,591,170	$328,843,874	$328,143,463	$327,443,052	$326,742,642	$326,042,231	$325,341,820	$324,641,410	$323,940,999	$323,240,588	$322,540,178	$321,888,969	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,864,657	$1,860,429	$1,856,467	$1,852,504	$1,848,542	$1,844,579	$1,840,616	$1,836,654	$1,832,691	$1,828,729	$1,824,766	$1,821,082	$22,111,716
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$340,742	$339,970	$339,246	$338,522	$337,797	$337,073	$336,349	$335,625	$334,901	$334,177	$333,453	$332,780	$4,040,635
8. Investment Expenses														
a. Depreciation (e)		$794,181	$800,328	$800,328	$800,328	$800,328	$800,328	$800,328	$800,328	$800,328	$800,328	$800,328	$801,839	$9,599,298
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,999,580	$3,000,727	$2,996,040	$2,991,353	$2,986,667	$2,981,980	$2,977,293	$2,972,607	$2,967,920	$2,963,233	$2,958,547	$2,955,701	$35,751,649

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	$1,313	
3a. Less: Accumulated Depreciation	$460	$463	$466	$468	$471	$474	$477	$480	$482	$485	$488	$491	$494	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$853	$850	$847	$844	$841	$839	$836	$833	$830	$827	$825	$822	$819	
6. Average Net Investment		$851	$848	$846	$843	$840	$837	$834	$832	$829	$826	$823	$820	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$57
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$10
8. Investment Expenses														
a. Depreciation (e)		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$34
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$9	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$101

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

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31 - Clean Air Interstate Rule (CAIR) Compliance														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	$1,278,330	
3a. Less: Accumulated Depreciation	$237,582	$240,017	$242,452	$244,888	$247,323	$249,759	$252,194	$254,630	$257,065	$259,500	$261,936	$264,371	$266,807	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,040,748	$1,038,313	$1,035,878	$1,033,442	$1,031,007	$1,028,571	$1,026,136	$1,023,700	$1,021,265	$1,018,830	$1,016,394	$1,013,959	$1,011,523	
6. Average Net Investment		$1,039,531	$1,037,095	$1,034,660	$1,032,224	$1,029,789	$1,027,354	$1,024,918	$1,022,483	$1,020,047	$1,017,612	$1,015,176	$1,012,741	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5,881	$5,867	$5,854	$5,840	$5,826	$5,812	$5,798	$5,785	$5,771	$5,757	$5,743	$5,730	$69,664
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,075	$1,072	$1,070	$1,067	$1,065	$1,062	$1,060	$1,057	$1,055	$1,052	$1,050	$1,047	$12,730
8. Investment Expenses														
a. Depreciation (e)		$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$2,435	$29,225
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$9,391	$9,375	$9,359	$9,342	$9,326	$9,310	$9,293	$9,277	$9,261	$9,245	$9,228	$9,212	$111,620

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

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31 - Clean Air Interstate Rule (CAIR) Compliance														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	$55,890,251	
3a. Less: Accumulated Depreciation	($21,149,914)	($20,937,148)	($20,724,383)	($20,511,618)	($20,298,853)	($20,086,087)	($19,873,322)	($19,660,557)	($19,447,792)	($19,235,027)	($19,022,261)	($18,809,496)	($18,596,731)	
3b. Less: Capital Recovery Unamortized Balance	($46,257)	($45,615)	($44,973)	($44,330)	($43,688)	($43,045)	($42,403)	($41,760)	($41,118)	($40,475)	($39,833)	($39,190)	($38,548)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$77,086,422	$76,873,014	$76,659,606	$76,446,199	$76,232,791	$76,019,383	$75,805,975	$75,592,568	$75,379,160	$75,165,752	$74,952,345	$74,738,937	$74,525,529	
6. Average Net Investment		$76,979,718	$76,766,310	$76,552,902	$76,339,495	$76,126,087	$75,912,679	$75,699,272	$75,485,864	$75,272,456	$75,059,049	$74,845,641	$74,632,233	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$435,512	$434,304	$433,097	$431,890	$430,682	$429,475	$428,267	$427,060	$425,853	$424,645	$423,438	$422,231	$5,146,454
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$79,584	$79,364	$79,143	$78,922	$78,702	$78,481	$78,260	$78,040	$77,819	$77,599	$77,378	$77,157	$940,449
8. Investment Expenses														
a. Depreciation (e)		$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$212,765	$2,553,183
b. Amortization (f)		$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$7,710
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$728,503	$727,076	$725,648	$724,220	$722,792	$721,364	$719,936	$718,508	$717,080	$715,652	$714,224	$712,796	$8,647,795

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
33 - MATS Project														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	$109,331,489	
3a. Less: Accumulated Depreciation	$30,717,142	$30,971,821	$31,226,500	$31,481,179	$31,735,859	$31,990,538	$32,245,217	$32,499,896	$32,754,575	$33,009,254	$33,263,933	$33,518,612	$33,773,291	
3b. Less: Capital Recovery Unamortized Balance	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	($84,067)	
4. CWIP	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	
5. Net Investment (Lines 2 - 3 + 4)	$78,698,418	$78,443,739	$78,189,060	$77,934,381	$77,679,702	$77,425,023	$77,170,344	$76,915,665	$76,660,986	$76,406,307	$76,151,627	$75,896,948	$75,642,269	
6. Average Net Investment		$78,571,078	$78,316,399	$78,061,720	$77,807,041	$77,552,362	$77,297,683	$77,043,004	$76,788,325	$76,533,646	$76,278,967	$76,024,288	$75,769,609	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$444,515	$443,074	$441,633	$440,192	$438,751	$437,310	$435,870	$434,429	$432,988	$431,547	$430,106	$428,665	$5,239,081
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$81,229	$80,966	$80,703	$80,440	$80,176	$79,913	$79,650	$79,386	$79,123	$78,860	$78,596	$78,333	$957,375
8. Investment Expenses														
a. Depreciation (e)		$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$254,679	$3,056,149
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$780,423	$778,719	$777,015	$775,311	$773,607	$771,902	$770,198	$768,494	$766,790	$765,086	$763,382	$761,678	$9,252,605

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
34 - St Lucie Cooling Water System Inspection & Maintenance														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	
5. Net Investment (Lines 2 - 3 + 4)	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	
6. Average Net Investment		$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	$4,449,846	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$25,175	$25,175	$25,175	$25,175	$25,175	$25,175	$25,175	$25,175	$25,175	$25,175	$25,175	$25,175	$302,099
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$4,600	$4,600	$4,600	$4,600	$4,600	$4,600	$4,600	$4,600	$4,600	$4,600	$4,600	$4,600	$55,205
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$29,775	$357,304

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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35 - Martin Plant Drinking Water System Compliance														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	$134,173	
3a. Less: Accumulated Depreciation	$33,986	$34,268	$34,550	$34,832	$35,114	$35,395	$35,677	$35,959	$36,241	$36,522	$36,804	$37,086	$37,368	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$100,186	$99,905	$99,623	$99,341	$99,059	$98,778	$98,496	$98,214	$97,932	$97,651	$97,369	$97,087	$96,805	
6. Average Net Investment		$100,046	$99,764	$99,482	$99,200	$98,918	$98,637	$98,355	$98,073	$97,791	$97,510	$97,228	$96,946	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$566	$564	$563	$561	$560	$558	$556	$555	$553	$552	$550	$548	$6,687
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$103	$103	$103	$103	$102	$102	$102	$101	$101	$101	$101	$100	$1,222
8. Investment Expenses														
a. Depreciation (e)		$282	$282	$282	$282	$282	$282	$282	$282	$282	$282	$282	$282	$3,381
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$951	$949	$947	$946	$944	$942	$940	$938	$936	$934	$932	$930	$11,290

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

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35 - Martin Plant Drinking Water System Compliance														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	$101,218	
3a. Less: Accumulated Depreciation	$25,639	$25,852	$26,064	$26,277	$26,489	$26,702	$26,914	$27,127	$27,339	$27,552	$27,765	$27,977	$28,190	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$75,579	$75,367	$75,154	$74,942	$74,729	$74,516	$74,304	$74,091	$73,879	$73,666	$73,454	$73,241	$73,028	
6. Average Net Investment		$75,473	$75,260	$75,048	$74,835	$74,623	$74,410	$74,198	$73,985	$73,772	$73,560	$73,347	$73,135	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$427	$426	$425	$423	$422	$421	$420	$419	$417	$416	$415	$414	$5,044
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$78	$78	$78	$77	$77	$77	$77	$76	$76	$76	$76	$76	$922
8. Investment Expenses														
a. Depreciation (e)		$213	$213	$213	$213	$213	$213	$213	$213	$213	$213	$213	$213	$2,551
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$718	$716	$715	$713	$712	$710	$709	$708	$706	$705	$703	$702	$8,517

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

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36 - Low-Level Radioactive Waste Storage														
Base														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	
3a. Less: Accumulated Depreciation	$2,982,053	$3,022,012	$3,061,971	$3,101,930	$3,141,888	$3,181,847	$3,221,806	$3,261,765	$3,301,724	$3,341,682	$3,381,641	$3,421,600	$3,461,559	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$14,474,750	$14,434,792	$14,394,833	$14,354,874	$14,314,915	$14,274,956	$14,234,998	$14,195,039	$14,155,080	$14,115,121	$14,075,162	$14,035,204	$13,995,245	
6. Average Net Investment		$14,454,771	$14,414,812	$14,374,853	$14,334,895	$14,294,936	$14,254,977	$14,215,018	$14,175,059	$14,135,101	$14,095,142	$14,055,183	$14,015,224	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$81,778	$81,552	$81,326	$81,099	$80,873	$80,647	$80,421	$80,195	$79,969	$79,743	$79,517	$79,291	$966,411
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$14,944	$14,903	$14,861	$14,820	$14,779	$14,737	$14,696	$14,655	$14,613	$14,572	$14,531	$14,489	$176,599
8. Investment Expenses														
a. Depreciation (e)		$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$479,506
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$136,680	$136,413	$136,146	$135,878	$135,611	$135,343	$135,076	$134,809	$134,541	$134,274	$134,007	$133,739	$1,622,516

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
37 - DeSoto Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$5,088	$0	$0	$101,750	$0	$106,838
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,018)	$106,838	$0	$104,820
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,018)	$0	$0	($2,018)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$153,500,389	$153,500,389	$153,500,389	$153,500,389	$153,500,389	$153,500,389	$153,500,389	$153,500,389	$153,500,389	$153,500,389	$153,498,371	$153,605,209	$153,605,209	
3a. Less: Accumulated Depreciation	$57,340,913	$57,785,623	$58,230,333	$58,675,043	$59,119,752	$59,564,462	$60,009,172	$60,453,882	$60,898,592	$61,343,302	$61,785,965	$62,230,769	$62,675,722	
4. CWIP	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$5,088	$5,088	$5,088	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$96,159,476	$95,714,766	$95,270,056	$94,825,346	$94,380,636	$93,935,927	$93,491,217	$93,046,507	$92,606,885	$92,162,175	$91,717,493	$91,374,440	$90,929,487	
6. Average Net Investment		$95,937,121	$95,492,411	$95,047,701	$94,602,991	$94,158,281	$93,713,572	$93,268,862	$92,826,696	$92,384,530	$91,939,834	$91,545,967	$91,151,964	
a. Average ITC Balance		$27,525,993	$27,403,927	$27,281,861	$27,159,795	$27,037,729	$26,915,663	$26,793,597	$26,671,531	$26,549,465	$26,427,399	$26,305,333	$26,183,267	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$581,778	$579,089	$576,400	$573,711	$571,023	$568,334	$565,645	$562,970	$560,295	$557,607	$555,205	$552,803	$6,804,861
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$105,477	$104,990	$104,502	$104,014	$103,527	$103,039	$102,551	$102,066	$101,581	$101,094	$100,658	$100,223	$1,233,722
8. Investment Expenses														
a. Depreciation (e)		$432,523	$432,523	$432,523	$432,523	$432,523	$432,523	$432,523	$432,523	$432,523	$432,495	$432,616	$432,766	$5,190,583
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$12,187	$146,244
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($1,924,740)
9. Total System Recoverable Costs (Lines 7 & 8)		$971,570	$968,394	$965,217	$962,041	$958,864	$955,687	$952,511	$949,351	$946,192	$942,987	$940,272	$937,584	$11,450,670

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
38 - Space Coast Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$101,750	$0	$101,750
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$101,750	$0	$101,750
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$70,556,546	$70,556,546	$70,556,546	$70,556,546	$70,556,546	$70,556,546	$70,556,546	$70,556,546	$70,556,546	$70,556,546	$70,556,546	$70,658,296	$70,658,296	
3a. Less: Accumulated Depreciation	$25,417,036	$25,615,936	$25,815,236	$26,014,537	$26,213,838	$26,413,138	$26,612,439	$26,811,740	$27,011,040	$27,210,341	$27,409,642	$27,609,082	$27,808,663	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$45,139,510	$44,940,610	$44,741,309	$44,542,009	$44,342,708	$44,143,407	$43,944,107	$43,744,806	$43,545,505	$43,346,205	$43,146,904	$43,049,213	$42,849,633	
6. Average Net Investment		$45,040,060	$44,840,960	$44,641,659	$44,442,358	$44,243,058	$44,043,757	$43,844,456	$43,645,156	$43,445,855	$43,246,554	$43,098,059	$42,949,423	
a. Average ITC Balance		$11,824,527	$11,773,338	$11,722,149	$11,670,960	$11,619,771	$11,568,582	$11,517,393	$11,466,204	$11,415,015	$11,363,826	$11,312,637	$11,261,448	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$271,574	$270,375	$269,175	$267,974	$266,774	$265,574	$264,374	$263,174	$261,974	$260,774	$259,861	$258,948	$3,180,551
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$49,268	$49,050	$48,832	$48,615	$48,397	$48,179	$47,962	$47,744	$47,526	$47,308	$47,143	$46,978	$577,002
8. Investment Expenses														
a. Depreciation (e)		$194,508	$194,909	$194,909	$194,909	$194,909	$194,909	$194,909	$194,909	$194,909	$194,909	$195,049	$195,188	$2,338,923
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$4,392	$52,704
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($807,156)
9. Total System Recoverable Costs (Lines 7 & 8)		$452,478	$451,463	$450,045	$448,627	$447,209	$445,791	$444,373	$442,956	$441,538	$440,120	$439,182	$438,243	$5,342,024

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
39 - Martin Next Generation Solar Energy Center														
Intermediate														
1. Investments														
a. Expenditures/Additions		$226,775	$226,775	$226,775	$226,775	$226,775	$226,775	$226,775	$226,775	$226,775	$226,775	$226,775	$226,775	$2,721,300
b. Clearings to Plant		$925,140	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,721,300	$3,646,440
c. Retirements		($6,985)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6,985)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$428,212,267	$429,137,407	$429,137,407	$429,137,407	$429,137,407	$429,137,407	$429,137,407	$429,137,407	$429,137,407	$429,137,407	$429,137,407	$429,137,407	$431,858,707	
3a. Less: Accumulated Depreciation	$125,453,904	$126,528,772	$127,611,703	$128,694,633	$129,777,564	$130,860,495	$131,943,425	$133,026,356	$134,109,286	$135,192,217	$136,275,147	$137,358,078	$138,444,274	
4. CWIP	$932,125	$226,775	$453,550	$680,325	$907,100	$1,133,875	$1,360,650	$1,587,425	$1,814,200	$2,040,975	$2,267,750	$2,494,525	$0	
5. Net Investment (Lines 2 - 3 + 4)	$303,690,489	$302,835,410	$301,979,254	$301,123,099	$300,266,943	$299,410,788	$298,554,632	$297,698,477	$296,842,321	$295,986,166	$295,130,010	$294,273,855	$293,414,434	
6. Average Net Investment		$303,262,949	$302,407,332	$301,551,177	$300,695,021	$299,838,866	$298,982,710	$298,126,555	$297,270,399	$296,414,243	$295,558,088	$294,701,932	$293,844,144	
a. Average ITC Balance		$82,095,625	$81,751,827	$81,408,029	$81,064,231	$80,720,433	$80,376,635	$80,032,837	$79,689,039	$79,345,241	$79,001,443	$78,657,645	$78,313,847	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,832,069	$1,826,741	$1,821,410	$1,816,079	$1,810,748	$1,805,417	$1,800,086	$1,794,755	$1,789,424	$1,784,093	$1,778,762	$1,773,421	$21,633,001
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$332,296	$331,333	$330,369	$329,405	$328,441	$327,478	$326,514	$325,550	$324,587	$323,623	$322,659	$321,694	$3,923,948
8. Investment Expenses														
a. Depreciation (e)		$1,032,299	$1,033,376	$1,033,376	$1,033,376	$1,033,376	$1,033,376	$1,033,376	$1,033,376	$1,033,376	$1,033,376	$1,033,376	$1,036,641	$12,402,695
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$49,555	$594,660
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($5,421,012)
9. Total System Recoverable Costs (Lines 7 & 8)		$2,794,467	$2,789,253	$2,782,958	$2,776,663	$2,770,369	$2,764,074	$2,757,779	$2,751,484	$2,745,190	$2,738,895	$2,732,600	$2,729,560	$33,133,292

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
41 - Manatee Temporary Heating System														
Distribution														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	$1,417,015	
3a. Less: Accumulated Depreciation	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
6. Average Net Investment		$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	$227,705	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,288	$1,288	$1,288	$1,288	$1,288	$1,288	$1,288	$1,288	$1,288	$1,288	$1,288	$1,288	$15,459
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$235	$235	$235	$235	$235	$235	$235	$235	$235	$235	$235	$235	$2,825
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$1,524	$18,284

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
41 - Manatee Temporary Heating System														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$400,000	$0	$0	$0	$0	$0	$400,000
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	$17,573,197	
3a. Less: Accumulated Depreciation	$6,652,206	$6,848,526	$7,044,846	$7,241,167	$7,437,487	$7,633,807	$7,830,127	$8,026,447	$8,222,767	$8,419,087	$8,615,408	$8,811,728	$9,008,048	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000	
5. Net Investment (Lines 2 - 3 + 4)	$10,920,991	$10,724,671	$10,528,351	$10,332,030	$10,135,710	$9,939,390	$9,743,070	$9,946,750	$9,750,430	$9,554,110	$9,357,789	$9,161,469	$8,965,149	
6. Average Net Investment		$10,822,831	$10,626,511	$10,430,190	$10,233,870	$10,037,550	$9,841,230	$9,844,910	$9,848,590	$9,652,270	$9,455,949	$9,259,629	$9,063,309	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$61,230	$60,119	$59,009	$57,898	$56,787	$55,677	$55,697	$55,718	$54,608	$53,497	$52,386	$51,276	$673,902
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$11,189	$10,986	$10,783	$10,580	$10,377	$10,174	$10,178	$10,182	$9,979	$9,776	$9,573	$9,370	$123,147
8. Investment Expenses														
a. Depreciation (e)		$196,320	$196,320	$196,320	$196,320	$196,320	$196,320	$196,320	$196,320	$196,320	$196,320	$196,320	$196,320	$2,355,842
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$268,739	$267,426	$266,112	$264,798	$263,485	$262,171	$262,196	$262,220	$260,907	$259,593	$258,279	$256,966	$3,152,890

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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JANUARY 2021 THROUGH DECEMBER 2021

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

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
42 - Turkey Point Cooling Canal Monitoring Plan														
Base														
1. Investments														
a. Expenditures/Additions		$289,696	$300,926	$327,995	$375,215	$373,797	$363,968	$345,252	$845,252	$1,636,399	$1,643,859	$1,636,399	$1,636,399	$9,775,157
b. Clearings to Plant		$0	$0	$0	$0	$0	$766,855	$0	$0	$3,947,654	$0	$0	$4,803,480	$9,517,990
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$45,298,724	$45,298,724	$45,298,724	$45,298,724	$45,298,724	$45,298,724	$46,065,579	$46,065,579	$46,065,579	$50,013,233	$50,013,233	$50,013,233	$54,816,713	
3a. Less: Accumulated Depreciation	$4,644,567	$4,763,125	$4,881,682	$5,000,240	$5,118,797	$5,237,355	$5,356,912	$5,477,470	$5,598,027	$5,723,733	$5,854,588	$5,985,442	$6,122,561	
4. CWIP	$4,596,109	$4,885,805	$5,186,731	$5,514,726	$5,889,940	$6,263,737	$5,860,851	$6,206,103	$7,051,355	$4,740,100	$6,383,959	$8,020,358	$4,853,276	
5. Net Investment (Lines 2 - 3 + 4)	$45,250,265	$45,421,404	$45,603,772	$45,813,210	$46,069,867	$46,325,107	$46,569,518	$46,794,212	$47,518,907	$49,029,599	$50,542,604	$52,048,149	$53,547,429	
6. Average Net Investment		$45,335,834	$45,512,588	$45,708,491	$45,941,539	$46,197,487	$46,447,312	$46,681,865	$47,156,559	$48,274,253	$49,786,102	$51,295,376	$52,797,789	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$256,487	$257,487	$258,595	$259,914	$261,362	$262,775	$264,102	$266,788	$273,111	$281,664	$290,203	$298,703	$3,231,189
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$46,870	$47,052	$47,255	$47,496	$47,761	$48,019	$48,261	$48,752	$49,908	$51,471	$53,031	$54,584	$590,459
8. Investment Expenses														
a. Depreciation (e)		$118,557	$118,557	$118,557	$118,557	$118,557	$119,558	$120,558	$120,558	$125,706	$130,854	$130,854	$137,119	$1,477,994
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$421,914	$423,097	$424,407	$425,967	$427,679	$430,351	$432,921	$436,097	$448,724	$463,989	$474,088	$490,406	$5,299,641

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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42 - Turkey Point Cooling Canal Monitoring Plan														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	$14,859,266	
3a. Less: Accumulated Depreciation	$216,388	$245,240	$274,092	$302,943	$331,795	$360,647	$389,498	$418,350	$447,202	$476,054	$504,905	$533,757	$562,609	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$14,642,878	$14,614,026	$14,585,174	$14,556,322	$14,527,471	$14,498,619	$14,469,767	$14,440,916	$14,412,064	$14,383,212	$14,354,360	$14,325,509	$14,296,657	
6. Average Net Investment		$14,628,452	$14,599,600	$14,570,748	$14,541,897	$14,513,045	$14,484,193	$14,455,341	$14,426,490	$14,397,638	$14,368,786	$14,339,934	$14,311,083	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$82,760	$82,597	$82,434	$82,271	$82,107	$81,944	$81,781	$81,618	$81,454	$81,291	$81,128	$80,965	$982,350
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$15,123	$15,094	$15,064	$15,034	$15,004	$14,974	$14,944	$14,915	$14,885	$14,855	$14,825	$14,795	$179,512
8. Investment Expenses														
a. Depreciation (e)		$28,852	$28,852	$28,852	$28,852	$28,852	$28,852	$28,852	$28,852	$28,852	$28,852	$28,852	$28,852	$346,221
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$126,735	$126,542	$126,349	$126,156	$125,963	$125,770	$125,577	$125,384	$125,191	$124,998	$124,805	$124,612	$1,508,083

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
44 - Martin Plant Barley Barber Swamp Iron Mitigation														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	$93,890	
3a. Less: Accumulated Depreciation	$20,359	$20,556	$20,754	$20,951	$21,148	$21,345	$21,542	$21,740	$21,937	$22,134	$22,331	$22,528	$22,725	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$73,530	$73,333	$73,136	$72,939	$72,742	$72,544	$72,347	$72,150	$71,953	$71,756	$71,559	$71,361	$71,164	
6. Average Net Investment		$73,432	$73,234	$73,037	$72,840	$72,643	$72,446	$72,249	$72,051	$71,854	$71,657	$71,460	$71,263	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$415	$414	$413	$412	$411	$410	$409	$408	$407	$405	$404	$403	$4,912
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$76	$76	$76	$75	$75	$75	$75	$74	$74	$74	$74	$74	$898
8. Investment Expenses														
a. Depreciation (e)		$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$2,366
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$689	$687	$686	$685	$683	$682	$681	$679	$678	$677	$675	$674	$8,175

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
44 - Martin Plant Barley Barber Swamp Iron Mitigation														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	$70,829	
3a. Less: Accumulated Depreciation	$15,359	$15,508	$15,656	$15,805	$15,954	$16,102	$16,251	$16,400	$16,549	$16,697	$16,846	$16,995	$17,144	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$55,470	$55,321	$55,173	$55,024	$54,875	$54,727	$54,578	$54,429	$54,280	$54,132	$53,983	$53,834	$53,685	
6. Average Net Investment		$55,396	$55,247	$55,098	$54,950	$54,801	$54,652	$54,503	$54,355	$54,206	$54,057	$53,908	$53,760	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$313	$313	$312	$311	$310	$309	$308	$308	$307	$306	$305	$304	$3,705
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$57	$57	$57	$57	$57	$57	$56	$56	$56	$56	$56	$56	$677
8. Investment Expenses														
a. Depreciation (e)		$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$1,785
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$519	$518	$517	$516	$515	$514	$513	$512	$511	$510	$509	$508	$6,167

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
45 - 800 MW Unit ESP														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	$63,759	
3a. Less: Accumulated Depreciation	$21,340	$21,745	$22,150	$22,555	$22,960	$23,365	$23,770	$24,175	$24,579	$24,984	$25,389	$25,794	$26,199	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$42,418	$42,013	$41,608	$41,203	$40,799	$40,394	$39,989	$39,584	$39,179	$38,774	$38,369	$37,964	$37,560	
6. Average Net Investment		$42,216	$41,811	$41,406	$41,001	$40,596	$40,191	$39,786	$39,381	$38,977	$38,572	$38,167	$37,762	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$239	$237	$234	$232	$230	$227	$225	$223	$221	$218	$216	$214	$2,715
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$44	$43	$43	$42	$42	$42	$41	$41	$40	$40	$39	$39	$496
8. Investment Expenses														
a. Depreciation (e)		$405	$405	$405	$405	$405	$405	$405	$405	$405	$405	$405	$405	$4,858
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$687	$685	$682	$679	$677	$674	$671	$668	$666	$663	$660	$658	$8,069

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
45 - 800 MW Unit ESP														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	$108,369,392	
3a. Less: Accumulated Depreciation	($60,048,303)	($59,616,915)	($59,185,528)	($58,754,140)	($58,322,752)	($57,891,365)	($57,459,977)	($57,028,590)	($56,597,202)	($56,165,814)	($55,734,427)	($55,303,039)	($54,871,652)	
4. CWIP	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	($378)	
5. Net Investment (Lines 2 - 3 + 4)	$168,417,317	$167,985,929	$167,554,542	$167,123,154	$166,691,767	$166,260,379	$165,828,991	$165,397,604	$164,966,216	$164,534,829	$164,103,441	$163,672,053	$163,240,666	
6. Average Net Investment		$168,201,623	$167,770,236	$167,338,848	$166,907,460	$166,476,073	$166,044,685	$165,613,298	$165,181,910	$164,750,522	$164,319,135	$163,887,747	$163,456,360	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$951,598	$949,158	$946,717	$944,276	$941,836	$939,395	$936,955	$934,514	$932,074	$929,633	$927,192	$924,752	$11,258,100
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$173,892	$173,446	$173,000	$172,554	$172,109	$171,663	$171,217	$170,771	$170,325	$169,879	$169,433	$168,987	$2,057,274
8. Investment Expenses														
a. Depreciation (e)		$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$431,388	$5,176,651
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$1,556,878	$1,553,992	$1,551,105	$1,548,219	$1,545,332	$1,542,445	$1,539,559	$1,536,672	$1,533,786	$1,530,899	$1,528,013	$1,525,126	$18,492,026

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

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47 - NPDES Permit Renewal Requirements														
Base														
1. Investments														
a. Expenditures/Additions		$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$0	$0	$0	$0	$0	$0	$1,200,000
b. Clearings to Plant		$0	$0	$0	$0	$0	$3,500,000	$0	$0	$0	$0	$0	$0	$3,500,000
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$38,004	$38,004	$38,004	$38,004	$38,004	$38,004	$3,538,004	$3,538,004	$3,538,004	$3,538,004	$3,538,004	$3,538,004	$3,538,004	
3a. Less: Accumulated Depreciation	$800	$1,029	$1,258	$1,486	$1,715	$1,944	$5,454	$12,245	$19,036	$25,827	$32,618	$39,409	$46,200	
4. CWIP	$2,264,262	$2,464,262	$2,664,262	$2,864,262	$3,064,262	$3,264,262	($35,738)	($35,738)	($35,738)	($35,738)	($35,738)	($35,738)	($35,738)	
5. Net Investment (Lines 2 - 3 + 4)	$2,301,466	$2,501,237	$2,701,008	$2,900,780	$3,100,551	$3,300,322	$3,496,812	$3,490,021	$3,483,230	$3,476,439	$3,469,648	$3,462,857	$3,456,066	
6. Average Net Investment		$2,401,351	$2,601,123	$2,800,894	$3,000,665	$3,200,437	$3,398,567	$3,493,417	$3,486,626	$3,479,835	$3,473,043	$3,466,252	$3,459,461	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$13,586	$14,716	$15,846	$16,976	$18,106	$19,227	$19,764	$19,726	$19,687	$19,649	$19,610	$19,572	$216,465
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,483	$2,689	$2,896	$3,102	$3,309	$3,514	$3,612	$3,605	$3,598	$3,591	$3,584	$3,577	$39,556
8. Investment Expenses														
a. Depreciation (e)		$229	$229	$229	$229	$229	$3,510	$6,791	$6,791	$6,791	$6,791	$6,791	$6,791	$45,400
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$16,297	$17,634	$18,970	$20,307	$21,644	$26,251	$30,167	$30,121	$30,076	$30,030	$29,985	$29,940	$301,421

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
50 - Steam Electric Effluent Guidelines Revised Rules														
Base														
1. Investments														
a. Expenditures/Additions		$0	$535,943	$535,943	$535,943	$535,943	$535,943	$535,943	$535,943	$535,943	$535,943	$535,943	$1,071,885	$6,431,311
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,816,133	$6,816,133
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$1,193,077	$1,193,077	$1,193,077	$1,193,077	$1,193,077	$1,193,077	$1,193,077	$1,193,077	$1,193,077	$1,193,077	$1,193,077	$1,193,077	$8,009,210	
3a. Less: Accumulated Depreciation	$1,387	$4,161	$6,935	$9,709	$12,483	$15,256	$18,030	$20,804	$23,578	$26,352	$29,126	$31,900	$42,598	
4. CWIP	$384,822	$384,822	$920,765	$1,456,707	$1,992,650	$2,528,593	$3,064,535	$3,600,478	$4,136,420	$4,672,363	$5,208,306	$5,744,248	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,576,512	$1,573,738	$2,106,907	$2,640,076	$3,173,244	$3,706,413	$4,239,582	$4,772,750	$5,305,919	$5,839,088	$6,372,256	$6,905,425	$7,966,613	
6. Average Net Investment		$1,575,125	$1,840,322	$2,373,491	$2,906,660	$3,439,829	$3,972,997	$4,506,166	$5,039,335	$5,572,503	$6,105,672	$6,638,841	$7,436,019	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$8,911	$10,412	$13,428	$16,444	$19,461	$22,477	$25,494	$28,510	$31,526	$34,543	$37,559	$42,069	$290,834
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,628	$1,903	$2,454	$3,005	$3,556	$4,107	$4,659	$5,210	$5,761	$6,312	$6,863	$7,688	$53,146
8. Investment Expenses														
a. Depreciation (e)		$2,774	$2,774	$2,774	$2,774	$2,774	$2,774	$2,774	$2,774	$2,774	$2,774	$2,774	$10,698	$41,211
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$13,314	$15,088	$18,656	$22,223	$25,791	$29,358	$32,926	$36,494	$40,061	$43,629	$47,196	$60,454	$385,191

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
54 - Coal Combustion Residuals														
Base														
1. Investments														
a. Expenditures/Additions		$0	$469,415	$469,415	$469,415	$469,415	$469,415	$469,415	$469,415	$469,415	$469,415	$469,415	$938,830	$5,632,982
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,752,560	$10,752,560
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$104,927,958	$104,927,958	$104,927,958	$104,927,958	$104,927,958	$104,927,958	$104,927,958	$104,927,958	$104,927,958	$104,927,958	$104,927,958	$104,927,958	$115,680,519	
3a. Less: Accumulated Depreciation	$3,624,609	$3,845,420	$4,066,231	$4,287,042	$4,507,853	$4,728,664	$4,949,475	$5,170,286	$5,391,097	$5,611,908	$5,832,719	$6,053,530	$6,286,840	
3b. Less: Capital Recovery Unamortized Balance	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	($55,250)	
4. CWIP	$5,119,579	$5,119,579	$5,588,994	$6,058,409	$6,527,824	$6,997,239	$7,466,654	$7,936,069	$8,405,485	$8,874,900	$9,344,315	$9,813,730	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$106,478,178	$106,257,367	$106,505,971	$106,754,575	$107,003,180	$107,251,784	$107,500,388	$107,748,992	$107,997,596	$108,246,201	$108,494,805	$108,743,409	$109,448,928	
6. Average Net Investment		$106,367,773	$106,381,669	$106,630,273	$106,878,878	$107,127,482	$107,376,086	$107,624,690	$107,873,294	$108,121,899	$108,370,503	$108,619,107	$109,096,169	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$601,774	$601,853	$603,259	$604,666	$606,072	$607,479	$608,885	$610,292	$611,698	$613,104	$614,511	$617,210	$7,300,802
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$109,967	$109,981	$110,238	$110,495	$110,752	$111,009	$111,266	$111,523	$111,780	$112,037	$112,294	$112,787	$1,334,129
8. Investment Expenses														
a. Depreciation (e)		$220,811	$220,811	$220,811	$220,811	$220,811	$220,811	$220,811	$220,811	$220,811	$220,811	$220,811	$233,311	$2,662,231
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$932,552	$932,645	$934,308	$935,972	$937,635	$939,299	$940,962	$942,626	$944,289	$945,952	$947,616	$963,308	$11,297,162

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

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JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
123 - Protected Species Project														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$30,525	$0	$0	$0	$0	$0	$172,975	$0	$0	$0	$203,500
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$203,500	$0	$0	$0	$203,500
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)		$0	$0	$0	$0	$0	$0	$0	$0	$203,500	$203,500	$203,500	$203,500	
3a. Less: Accumulated Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$198	$595	$992	$1,389	
4. CWIP		$0	$0	$30,525	$30,525	$30,525	$30,525	$30,525	$30,525	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)		$0	$0	$30,525	$30,525	$30,525	$30,525	$30,525	$30,525	$203,302	$202,905	$202,508	$202,111	
6. Average Net Investment		$0	$0	$15,263	$30,525	$30,525	$30,525	$30,525	$30,525	$116,913	$203,103	$202,706	$202,310	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$0	$86	$173	$173	$173	$173	$173	$661	$1,149	$1,147	$1,145	$5,052
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$0	$0	$16	$32	$32	$32	$32	$32	$121	$210	$210	$209	$923
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$198	$397	$397	$397	$1,389
b. Amortization (f)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (g)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
														$0
9. Total System Recoverable Costs (Lines 7 & 8)		$0	$0	$102	$204	$204	$204	$204	$204	$981	$1,756	$1,753	$1,751	$7,364

(a) Applicable to reserve salvage and removal cost.
(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 62-64.
(c) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(d) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(e) Applicable depreciation rate or rates. See Form 42-4P, pages 62-64.
(f) Applicable amortization period(s). See Form 42-4P, pages 62-64.
(g) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).
(h) For solar projects the return on investment calculation is comprised of two parts:
Return on the Average Net Investment: See footnotes (b) and (c).
Return on the Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%; the Equity Component for the Jan. – Dec. 2021 period is 6.408% based on the 2021 Forecasted Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2021 period is 1.515% based on the 2021 Forecasted Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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JANUARY 2021 THROUGH DECEMBER 2021

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	Septemeber Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Total
Amortization of Gains on Sales of Emissions Allowances														
Base														
1 Working Capital Dr (Cr)														
a 158.100Allowance Inventory														
b 158.200Allowances Withheld														
c 182.300Other Regulatory Assets-Losses														
d 254.900Other Regulatory Liabilities-Gains	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	
2 Total Working Capital	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	
3 Average Net Working Capital Balance		($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	($183)	
4 Return on Average Net Working Capital Balance														
a Equity Component grossed up for taxes (A)		($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	
b Debt Component (Line 6 x 1.6698% x 1/12)		($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
5 Total Return Component		($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($15)
6 Expense Dr (Cr)														
a 411.800Gains from Dispositions of Allowances														
b 411.900Losses from Dispositions of Allowances														
c 509.000Allowance Expense														
7 Net Expense (Lines 6a+6b+6c)														
8 Total System Recoverable Expenses (Lines 5+7)		($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($15)

(a) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Surveillance Report and reflects a 10.55% return on equity.
(b) The Debt Component for the Jan. – Dec. 2021 period is 1.2406 based on the 2021 Forecasted Surveillance Report.
(c) Line 5 is reported on Capital Schedule 3P-1.
(d) Line 7 is reported on O&M Schedule 2P-1.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FORM: 42-4P

2021 Annual Capital Depreciation Schedule

Project	Function	Plant	Unit	Utility	DEPR RATE	Sum of Dec-20	Sum of Dec-21
002-LOW NOX BURNER TECHNOLOGY	02 - Steam Generation Plant	Turkey Pt	Turkey Pt U1	31200	0.00%	-	-
002-LOW NOX BURNER TECHNOLOGY Total						-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	65,605	65,605
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee U1	31100	1.74%	56,430	56,430
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	424,505	424,505
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee U2	31100	1.83%	56,333	56,333
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	468,728	468,728
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin	Martin Comm	31670	7-Year	(4,473)	(59,381)
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	515,653	515,653
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale GTs	34300	8.25%	10,225	10,225
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Myers	FtMyers U2	34300	3.46%	365,000	365,000
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Myers	FtMyers U3	34100	3.38%	6,098	6,098
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Myers	FtMyers U3	34300	4.54%	71,939	71,939
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Myers	FtMyers U3 SC Peaker	34300	3.04%	69,082	69,082
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Manatee	Manatee U3	34300	3.35%	87,691	87,691
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin	Martin U3	34300	4.49%	615,469	615,469
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin	Martin U4	34300	3.92%	598,036	598,036
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin	Martin U8	34300	3.37%	13,693	13,693
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford	Sanford U4	34300	4.00%	310,021	310,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford	Sanford U5	34300	4.12%	273,035	273,035
003-CONTINUOUS EMISSION MONITORING Total						4,003,071	3,948,163
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	3,111,263	3,111,263
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	174,543	174,543
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	104,845	104,845
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	127,429	127,429
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	133,572	133,572
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin	Martin Comm U1&2	31100	2.52%	65,093	65,093
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34200	3.09%	898,111	898,111
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale GTs	34200	4.73%	584,290	584,290
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34200	7.84%	133,479	133,479
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Ft Myers	FtMyers U3	34200	3.58%	18,616	18,616
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Martin	Martin Comm U3&4	34200	2.42%	455,941	455,941
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	08 - General Plant	General Plant	General Plant	39000	1.50%	8,224,667	8,224,667
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total						14,031,849	14,031,849
007-RELOCATE TURBINE LUBE OIL PIPING	03 - Nuclear Generation Plant	St Lucie	StLucie U1	32300	5.11%	31,030	31,030
007-RELOCATE TURBINE LUBE OIL PIPING Total						31,030	31,030
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	46,882	46,882
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee	Manatee U1	31100	1.74%	52,481	52,481
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin	Martin Comm	31650	5-Year	263,879	317,516
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin	Martin Comm	31670	7-Year	258,350	216,928
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34100	2.20%	358,636	358,636
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Ft Myers	FtMyers U2	34100	2.34%	405,369	405,369
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Pt Everglades	PtEverglades U5	34100	2.64%	22,550	22,550
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Sanford	Sanford Comm	34100	2.40%	15,922	15,922
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36670	2.00%	2,995	2,995
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	General Plant	39000	1.50%	4,413	4,413
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total						1,431,477	1,443,692
010-REROUTE STORMWATER RUNOFF	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	117,794	117,794
010-REROUTE STORMWATER RUNOFF Total						117,794	117,794
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer	Scherer Comm	31100	1.51%	524,873	524,873
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer	Scherer Comm	31200	2.23%	328,762	328,762
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer	Scherer Comm	31400	2.08%	689	689
012-SCHERER DISCHARGE PIPELINE Total						854,324	854,324
016-ST.LUCIE TURTLE NETS	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	6,909,559	6,909,559
016-ST.LUCIE TURTLE NETS Total						6,909,559	6,909,559
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin	Martin U1	31200	0.00%	-	-
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin	Martin U2	31200	0.00%	-	-
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total						-	-
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	601,217	601,217
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	2,271,574	2,271,574
022-PIPELINE INTEGRITY MANAGEMENT Total						2,872,791	2,872,791
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	1,243,306	1,243,306
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	33,272	33,272
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee Comm	31500	2.34%	26,325	26,325
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	45,750	45,750
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	37,431	37,431
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	37,158	37,158
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	St Lucie	StLucie U1	32300	5.11%	712,225	712,225
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	St Lucie	StLucie U1	32400	3.20%	745,335	745,335
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	St Lucie	StLucie U2	32300	3.86%	552,390	552,390
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32100	3.13%	990,124	990,124
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32570	7-Year	245,362	245,362
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34100	2.20%	189,219	689,219
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34200	3.09%	1,480,169	1,480,169
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34300	5.20%	28,250	28,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale GTs	34200	4.73%	513,250	513,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34100	7.40%	98,715	98,715
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34200	7.84%	629,983	629,983
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34500	7.77%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U2	34100	2.34%	425,728	425,728
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U2	34300	3.46%	49,727	49,727
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U3	34500	3.40%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U3 SC Peaker	34500	3.40%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin	Martin Comm U3&4	34100	2.24%	1,080,186	1,080,186
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin	Martin U8	34200	2.70%	84,868	84,868
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Pt Everglades	PtEverglades Comm	34200	2.90%	2,728,283	2,728,283
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Pt Everglades	PtEverglades U5	34200	2.90%	286,434	286,434
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Sanford	Sanford Comm	34100	2.40%	288,383	288,383

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Project	Function	Plant	Unit	Utility	DEPR RATE	Sum of Dec-20	Sum of Dec-21
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Radial-Retail	Radial-Retail	35200	1.70%	6,946	6,946
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35200	1.70%	1,142,640	1,142,640
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	2.04%	2,902,891	2,902,891
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35800	1.87%	65,655	65,655
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36100	1.75%	3,506,546	3,506,546
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36670	2.00%	70,499	70,499
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	08 - General Plant	General Plant	General Plant	39000	1.50%	146,691	146,691
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total						20,418,601	20,918,601
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	16,470,024	16,470,024
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	15,393,694	15,393,694
024-GAS REBURN Total						31,863,719	31,863,719
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	Pt Everglades	PtEverglades U1	31100	0.00%	-	-
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	Pt Everglades	PtEverglades U2	31100	0.00%	-	-
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	Pt Everglades	PtEverglades U3	31100	0.00%	-	-
025-PPE ESP TECHNOLOGY	02 - Steam Generation Plant	Pt Everglades	PtEverglades U4	31100	0.00%	-	-
025-PPE ESP TECHNOLOGY Total						-	-
026-UST REPLACEMENT/REMOVAL	08 - General Plant	General Plant	General Plant	39000	1.50%	115,447	115,447
026-UST REPLACEMENT/REMOVAL Total						115,447	115,447
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	Cape Canaveral	CapeCanaveral Comm	34100	2.69%	771,310	771,310
028-CWA 316B PHASE II RULE Total						771,310	771,310
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee Comm	31100	3.17%	102,052	102,052
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	20,059,060	20,059,060
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee U1	31400	4.03%	7,240,124	7,240,124
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	20,457,354	20,457,354
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee	Manatee U2	31400	3.72%	7,905,907	7,905,907
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer Comm U3&4	31200	2.32%	4,976,687	4,976,687
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31100	2.30%	82,366,984	82,366,984
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	254,475,936	256,039,651
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31400	1.89%	(94,224)	(94,224)
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31500	2.49%	19,615,426	19,615,426
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31600	1.88%	399,586	399,586
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer U4	31670	7-Year	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale GTs	34300	8.25%	110,242	110,242
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Ft Myers	FtMyers GTs	34300	8.22%	57,855	57,855
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin	Martin Comm U3&4	34100	2.24%	699,143	699,143
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin	Martin Comm U3&4	34300	2.56%	244,343	244,343
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin	Martin Comm U3&4	34500	2.04%	292,499	292,499
031-CLEAN AIR INTERSTATE RULE-CAIR	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36500	2.57%	1,313	1,313
031-CLEAN AIR INTERSTATE RULE-CAIR Total						418,910,287	420,474,002
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer	Scherer Comm U3&4	31200	2.32%	(1,234,037)	(1,234,037)
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	110,565,526	110,565,526
033-CLEAN AIR MERCURY RULE-CAMR Total						109,331,489	109,331,489
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	-	-
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE Total						-	-
035-MARTIN PLANT DRINKING WATER COMP	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	235,391	235,391
035-MARTIN PLANT DRINKING WATER COMP Total						235,391	235,391
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	7,601,405	7,601,405
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32100	3.13%	9,855,399	9,855,399
036-LOW LEV RADI WSTE-LLW Total						17,456,804	17,456,804
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34000	0.00%	255,507	255,507
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34100	3.49%	5,263,916	5,263,916
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34300	3.36%	115,297,623	115,404,461
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34500	3.65%	26,746,246	26,746,246
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34630	3-Year	7,279	5,261
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34650	5-Year	24,247	24,247
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34670	7-Year	152,115	152,115
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35200	1.70%	7,427	7,427
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	2.04%	1,004,027	1,004,027
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35310	2.64%	1,695,869	1,695,869
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35500	2.32%	394,418	394,418
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35600	2.38%	191,358	191,358
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36100	1.75%	540,994	540,994
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36200	1.90%	1,890,938	1,890,938
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39220	10.00%	28,426	28,426
037-DE SOTO SOLAR PROJECT Total						153,500,389.02	153,605,209.00
038-SPACE COAST SOLAR PROJECT	01 - Intangible Plant	Intangible Plant	Intangible Plant	30300	various	6,359,027	6,359,027
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34100	3.45%	3,893,263	3,893,263
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34300	3.30%	51,550,587	51,652,337
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34500	3.51%	6,126,699	6,126,699
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34650	5-Year	0	0
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34670	7-Year	337	337
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	2.04%	928,529	928,529
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35310	2.64%	1,328,699	1,328,699
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36100	1.75%	274,858	274,858
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36200	1.90%	62,689	62,689
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39220	10.00%	31,858	31,858
038-SPACE COAST SOLAR PROJECT Total						70,556,545.79	70,658,295.79
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin	Martin U8	34300	3.37%	423,126	423,126
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34000	0.00%	216,844	216,844
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34100	2.99%	20,756,023	20,756,023
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34300	2.88%	400,842,239	404,495,664
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34500	2.99%	4,170,831	4,170,831
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34600	2.85%	56,448	56,448
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34670	7-Year	138,981	131,996
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35500	2.32%	603,692	603,692
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35600	2.38%	364,159	364,159
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36660	1.42%	94,476	94,476
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36760	1.96%	2,728	2,728
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39220	10.00%	121,101	121,101
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39240	2.63%	332,682	332,682
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39290	4.99%	88,938	88,938
039-MARTIN SOLAR PROJECT Total						428,212,267	431,858,707

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Project	Function	Plant	Unit	Utility	DEPR RATE	Sum of Dec-20	Sum of Dec-21
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Cape Canaveral	CapeCanaveral Comm	34300	0.00%	4,042,459	4,042,459
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Dania Beach EC U7	Dania Beach EC U7	34300	44 mos.	7,927,191	7,927,191
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34300	44 mos.	-	-
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Ft Myers	FtMyers U2	34300	3.46%	5,603,547	5,603,547
041-PRV MANATEE HEATING SYSTEM	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	various	276,404	276,404
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36100	various	73,267	73,267
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36200	various	471,542	471,542
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36500	various	307,599	307,599
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36660	various	221,326	221,326
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36760	various	168,995	168,995
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36910	various	607	607
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36420	various	36,431	36,431
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36410	various	137,247	137,247
041-PRV MANATEE HEATING SYSTEM Total						**19,266,616**	**19,266,616**
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32100	3.13%	44,402,659	53,920,649
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32500	3.67%	896,065	896,065
042-PTN COOLING CANAL MONITORING SYS	05 - Other Generation Plant	Turkey Pt	Turkey Pt U5	34100	2.33%	14,859,266	14,859,266
042-PTN COOLING CANAL MONITORING SYS Total						**60,157,990**	**69,675,979**
044-Barley Barber Swamp Iron Mitiga	02 - Steam Generation Plant	Martin	Martin Comm	31100	2.52%	164,719	164,719
044-Barley Barber Swamp Iron Mitiga Total						**164,719**	**164,719**
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	153,660	153,660
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	44,485,716	44,485,716
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U1	31500	4.11%	4,524,074	4,524,074
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U1	31600	3.91%	1,021,918	1,021,918
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	52,279,530	52,279,530
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U2	31500	4.48%	4,793,798	4,793,798
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U2	31600	4.79%	1,174,454	1,174,454
045-800 MW UNIT ESP PROJECT Total						**108,433,151**	**108,433,151**
047-NPDES Permit Renewal Requiremnt	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	-	3,500,000
047-NPDES Permit Renewal Requiremnt	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32300	7.22%	38,004	38,004
047-NPDES Permit Renewal Requiremnt Total						**38,004**	**3,538,004**
050-STEAM ELEC EFFLUENT GUIDELI REV	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	1,193,077	8,009,210
050-STEAM ELEC EFFLUENT GUIDELI REV Total						**1,193,077**	**8,009,210**
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer	Scherer Comm	31100	1.51%	208,650	208,650
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer	Scherer Comm U3&4	31200	2.32%	58,529,330	58,529,330
054-COAL COMBUSTION RESIDUALS	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	46,189,978	56,942,539
054-COAL COMBUSTION RESIDUALS Total						**104,927,958**	**115,680,519**
123-PROTECTED SPECIES PROJECT	05 - Other Generation Plant	Ft Myers	FtMyers U2	34100	2.34%	-	203,500
123-PROTECTED SPECIES PROJECT Total						**-**	**203,500**
Grand Total						**1,575,805,658**	**1,612,469,873**

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Air Operating Permit Fees

Project No. 1

Project Description:

The Clean Air Act Amendments of 1990, Public Law 101-549, and Section 403.0872, Florida Statutes, require each major source of air pollution to pay an annual license fee. The amount of the fee is based on each source's previous year's emissions. The fee covers FPL's units in Florida, as well as FPL's ownership share of Plant Scherer's Unit 4 located in Juliette, Georgia. The fees for FPL's units in Florida are paid to the Florida Department of Environmental Protection ("DEP") in the first quarter of each year. FPL pays its share of the fees for Scherer Unit 4 to Georgia Power Company ("Georgia Power"), the operating agent, on a monthly basis for submittal to the Georgia Environmental Protection Division ("EPD").

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

O&M - Previous year's air operating permit fees for Florida facilities are calculated from final year ending generating unit emissions and DEP fees for each ton of regulated pollutant emitted. FPL submitted to the Florida DEP payment for the 2019 emissions following the first quarter of 2020 when data are finalized. Permit fees for FPL's ownership share of Scherer Unit 4 were paid monthly in 2019 to Georgia Power for their submittal to the Georgia EPD in 2020 based on preliminary monthly emission data and trued-up when emission data was finalized. During the projection period FPL estimated permit fees for 2020 emissions based on projected unit operation and fuel use with current approved DEP emission fees.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $157,384, which is $57,998 or 26.9% lower than previously projected. The Project costs for 2020 are lower than originally projected as a result of lower fuel use for 2020. FPL has adjusted its projected 2020 air permit fees based on the most recent projections for unit dispatch, fuel use, and DEP approved emission fee.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $184,714.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low NOx Burner Technology

Project No. 2

Project Description:

Under Title I of the Clean Air Act Amendments of 1990, Public Law 101-349, utilities with units located in areas designated as "non-attainment" for ozone will be required to reduce Nitrogen Oxide ("NOx") emissions by implementing Reasonably Available Control Technology. To comply with the state's plan to bring the Dade, Broward and Palm Beach county areas into compliance with the ozone air quality standard, FPL implemented NOx burner technology on its oil and gas-fired steam generating units in those counties to reduce emissions of the pollutants that contributed to the ozone non-attainment.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $57,069, which is $242 lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $54,180.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Continuous Emission Monitoring Systems ("CEMS")

Project No. 3

Project Description:

The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping, and reporting of SO_2, NOx, and CO_2 emissions from affected air pollution sources. FPL's fossil-fired generating units are affected by these regulations and CEMS have been installed to comply with these requirements. Operation and maintenance of CEMS in accordance with the provisions of 40 CFR Part 75 is an ongoing activity performed according to the requirements of the FPL CEMS Quality Assurance ("QA") Program Manual approved by the Environmental Protection Agency ("EPA").

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Operation, maintenance, and certification of the CEMS continues to be performed according to the requirements of the CEMS QA Program Manual, all applicable federal and state regulations, as well as local requirements. CEMS required parts are purchased as needed for repairs and/or preventative maintenance. CEMS analyzer calibration gases, that ensure accuracy of the measurements, are required to be used daily and are purchased as needed. FPL maintains its CEMS 24/7 Software Support contract with its CEMS vendor to ensure proper functionality as well as the integrity of the CEMS data. Training on the operation and maintenance of the system, as well as rule/regulation changes continue as needed.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are $40,832 or 11.9% higher than previously projected. The variance is primarily a result of two unplanned maintenance tasks at Plant Fort Myers ("PFM"): (1) additional maintenance required on aging CEMS equipment at PFM, and (2) pre-buying calibration gases in anticipation of COVID-19 related delays in securing the gases.

Capital - Project revenue requirements are estimated to be $467,855, which is $13,817, or 3.0% lower than previously projected.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $364,603.

Capital - Estimated project revenue requirements for the projection period are $445,012.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks

Project No. 5

Project Description:

Florida Administrative Code ("F.A.C.") Chapter 62-762, provides standards for the maintenance of stationary above ground fuel storage tank systems and associated piping. These standards impose various implementation schedules for internal and external inspections, coating, repairs and upgrades to FPL's fuel storage tanks including secondary containment, spill containment, release detection, overfill protection (e.g., high level alarms, level gauges, etc.) and cathodic protection. Inspections and work performed on the fuel storage tanks and piping must follow certain standards such as the American Petroleum Institute ("API") standards. The project also requires equipment testing and includes registration fees that must be paid to the DEP for tanks that are in operation.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. External inspections were completed for tanks at Manatee Plant, Fort Myers Plant and Port Everglades Plant. Touch-up coating work was completed on tanks at Turkey Point, Fort Myers Plant, Martin Terminal and Manatee Terminal.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are $85,005 or 14.3% lower than previously projected. The variance is primarily due to the fact that the Port Everglades Touch Up Re-coating Project that was included in the projection was completed prior to 2020.

Capital - Project revenue requirements are estimated to be $1,660,195, which is $56,424 or 4.0% higher than previously projected.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $392,202.

Capital - Estimated project revenue requirements for the projection period are $1,635,231.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Turbine Lube Oil Underground Piping to Above Ground

Project No. 7

Project Description:

In accordance with criteria contained in Chapter 62-762 F.A.C. for storage of pollutants, FPL replaced the underground turbine lube oil piping with above ground installations at the St. Lucie Nuclear Power Plant.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $1,535, which is on target for 2020.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $1,408.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Oil Spill Clean-up/Response Equipment

Project No. 8

Project Description:

The Oil Pollution Act of 1990 ("OPA 90") mandated that all regulated facilities that store or transfer oil over certain quantities and which reasonably could be expected to discharge oil into navigable waters prepare Facility Response Plans ("FRP") to address a worst case discharge of oil. The FRPs were required to be submitted to the appropriate agency (i.e., Coast Guard, EPA and DOT Pipeline & Hazardous Materials Administration) by August 18, 1993 or prior to going into operation. In these plans, a facility owner or operator must identify (among other items) its spill management team organization, response equipment and training, equipment inspection and exercise program. FPL developed plans for ten power plants, two fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

FRP updates continue to be performed for all sites as required. Routine maintenance of remaining oil spill equipment has continued throughout the year. Training, as well as planned third quarter and fourth quarter oil spill drills, are pending subject to COVID-19 conditions.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are $187,496 or 108.2% higher than previously projected. The variance is a result of increased oil spill response contractor costs in the form of a retainer associated with staging sufficient contractor-owned spill response equipment to meet FPL's worst case discharge requirements under Oil Pollution Act of 1990 regulations.

Capital - Project revenue requirements are $140,703 or 42.0% lower than previously projected. This variance is primarily a result of the cancellation of the oil boom project due to the planned retirement of Manatee Units 1 and 2.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $267,940.

Capital - Estimated project revenue requirements for the projection period are $208,086.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Storm Water Runoff

Project No. 10

Project Description:

The National Pollutant Discharge Elimination System ("NPDES") permit, Permit No. FL0002206 for the St. Lucie plant, issued by the EPA contains effluent discharge limitations for industrial-related storm water from the plant and land utilization building areas. The requirements became effective on January 1, 1994. As a result of these requirements, affected areas were surveyed, graded, excavated, and paved as necessary to clean and redirect the storm water runoff. The storm water runoff is collected and discharged to existing water catch basins on site.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $6,215, which is $44 or 1.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $6,026.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Scherer Discharge Pipeline

Project No. 12

Project Description:

On March 16, 1992, pursuant to the provisions of the Georgia Water Control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated thereunder, the Georgia Department of Natural Resources ("the Department") issued the NPDES permit for Plant Scherer to Georgia Power. In addition to the permit, the Department issued Administrative Order EPD-WQ-1855, which provided a schedule for compliance by April 1, 1994 with the facility discharge limitations to Berry Creek. As a result of these limitations, and pursuant to the order, Georgia Power was required to construct an alternate outfall to redirect certain wastewater discharges to the Ocmulgee River. Pursuant to the ownership agreement with Georgia Power for Scherer Unit 4, FPL is required to pay for its share of construction of the discharge pipeline, which will constitute the alternate outfall.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $33,749, which is $229 or 1.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $32,646.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: NPDES Permit Fees

Project No. 14

Project Description:

In compliance with Rule 62-4.052, F.A.C., FPL is required to pay annual regulatory program and surveillance fees for any permits which are required to allow the discharge of wastewater to surface waters under the NPDES. These fees implement the Florida Legislature's intent that the DEP's costs for administering the NPDES program be borne by the regulated parties, as applicable.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

The NPDES permit fees were paid to the FDEP for the seven applicable power generation and nuclear plants.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $69,200, which is $11,500 or 19.9% higher than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $69,200.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Disposal of Noncontainerized Liquid Waste

Project 17

Project Description:

FPL manages ash from heavy oil-fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. To comply with F.A.C. 62-701.300(10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project costs are estimated to be $0.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project costs for the projection period are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Substation Pollutant Discharge Prevention and Removal

Project 19a – Distribution, 19b - Transmission

Project Description:

Florida Statute Chapter 376 – Pollutant Discharge Prevention and Removal requires that any person discharging a pollutant, defined as any commodity made from oil or gas, shall immediately undertake to contain, remove and abate the discharge to the satisfaction of the DEP. This project includes the prevention and removal of pollutant discharges at FPL substations including equipment mineral oil and historical arsenic impacts.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Leak repair and regasketing work continues as needed on affected equipment identified during inspections. A mobile transformer has been utilized at five locations to date to alleviate energy load problems in critical substations in order to repair and regasket leaking transformers. It is anticipated that 3 more mobile transformers may be required to be utilized in the remainder of 2020. The arsenic remediation work continues to be addressed at four substations where historical impacts have been identified.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M -

19a. Project expenditures are $866,547 or 32.2% higher than previously projected. The variance is primarily due to FPL obtaining more equipment clearances (i.e., de-energize installed equipment) than expected, which are required for equipment repair. This resulted in a higher than projected number of transformers being repaired during the first half of 2020.

19b. Project expenditures are $277,405 or 27.5% higher than previously projected. The variance is primarily due to FPL obtaining more equipment clearances than expected, which are required for equipment repair. This resulted in a higher than projected number of transformers being repaired during the first half of 2020.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are:

19a. $2,927,122

19b. $1,266,116

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater Discharge Elimination & Reuse

Project No. 20

Project Description:

Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the DEP Industrial Wastewater Permits issued under 62-620 F.A.C., regulate discharges of any wastewater discharges to groundwater at all plants, and the Miami-Dade County Department of Environmental Resource Management requires the Turkey Point plant's and Cutler plant's wastewater discharges into canals to meet county water quality standards found in Section 24-42, Code of Miami-Dade County. In order to address these requirements, FPL has undertaken a multifaceted project, which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $42,408, which is $531 or 1.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $42,694.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Turtle Net

Project No. 21

Project Description:

The Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on March 24, 2015, by the National Marine Fisheries Service limits the number of lethal turtle "takings" permitted at its St. Lucie Power Plant. An effective 5-inch primary barrier net is vital to limiting the number of lethal turtle takes per year.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Inspections and cleaning were performed to remove algae and jellyfish buildup that occurred on the turtle net.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are estimated to be $69,118 or 18.8% lower than previously projected. The variance is primarily due to less significant and fewer than anticipated aquatic organism intrusion events, which resulted in lower turtle net cleaning costs.

Capital - Project revenue requirements are estimated to be $734,751, which is $7,250 or 1.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $368,400.

Capital - Estimated project revenue requirements for the projection period are $726,163.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management Program

Project No. 22

Project Description:

FPL is required to develop and implement a written pipeline integrity management program for its hazardous liquid/gas pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and (9) record keeping.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Cathodic protection surveys were completed for both the Manatee and Martin Fuel Terminals in Q1 2020. The Manatee TMT-16in pipeline inline inspection originally scheduled for Q2 2020 has been rescheduled for Q4 2020. The reason for the rescheduling is to ensure adequate hurricane season liquid levels are maintained in the Manatee Fuel Terminal tanks. Per DOT PHMSA regulations the Manatee TMT-16in pipeline inline inspection must be completed no later than January 21.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are estimated to be $327,500, which is on target for 2020.

Capital - Project revenue requirements are estimated to be $263,403, which is $2,340 or 1.0% lower than previously projected.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $77,500.

Capital - Estimated project revenue requirements for the projection period are $258,532.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Spill Prevention, Control, and Countermeasures ("SPCC") Program

Project No. 23

Project Description:

The EPA issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act) to prevent discharges of oil from reaching the navigable waters of the U.S. The SPCC rule also requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. As revised, the SPCC rule requires that each regulated facility prepare and implement an SPCC Plan; install secondary containment and/or diversionary structures for bulk oil storage containers, certain oil-filled equipment, piping and tank truck unloading racks/areas; provide overfill protection (e.g., tank level alarms, etc.); and conduct training, inspections, testing, security measures and facility drainage systems.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

FPL routinely reviews and updates the FRP and SPCC Plans for its power plant and fuel terminal facilities. These updates incorporate modifications to tanks, piping, equipment, transformers, containment features and drainage systems as well as enhancements to facility inspection programs. For this year, additional updates incorporate specific projects including demolition of the Lauderdale Plant, removal/modification of tanks at the Martin Terminal, and modifications at the Okeechobee Plant for interconnection with the new solar plant on the property.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $785,841, which is $9,097 or 1.1% lower than previously projected.

Capital - Project revenue requirements are estimated to be $2,221,898, which is $46,064, or 2.0% lower than previously projected.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $826,568.

Capital - Estimated project revenue requirements for the projection period are $2,255,265.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Plant Reburn

Project No. 24

Project Description:

This project involves installation of reburn technology in Manatee Units 1 and 2 to provide significant reductions in NOx emissions from Manatee Units 1 and 2 to reduce impacts to local ozone air quality impacts that the DEP had required FPL to achieve. FPL determined that reburn technology was the most cost-effective alternative to achieve significant reductions in NOx emissions. Reburn is an advanced NOx control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers to reduce emissions that do not require the use of reagents, catalysts, and pollution reduction or removal equipment.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Manatee plant completed burner igniter and assemblies inspections during the spring 2020 outage on Unit 2.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are estimated to be $23,672, which is $89,845 or 79.1% lower than previously projected. The variance is primarily due to a shift in the outage schedule causing the majority of the reburn work planned on Unit 1 in March to be postponed until 2021.

Capital - Project revenue requirements are estimated to be $2,979,301, which is $18,031 or 1.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $212,332.

Capital - Estimated project revenue requirements for the projection period are $2,865,912.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Underground Storage Tank ("UST") Replacement/Removal

Project No. 26

Project Description:

Chapter 62-761.500 of the F.A.C., dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that were installed before June 30, 1992.

UST Category-B tanks are tanks containing pollutants after June 30, 1992 or a hazardous substance after January 1, 1994 that shall have secondary containment. Small diameter piping that comes in contact with the soil that is connected to a UST shall have secondary containment if installed after December 10, 1990.

UST and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $6,651, which is $62 or 1.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $6,545.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Lowest Quality Water Source ("LQWS")

Project No. 27

Project Description:

The LQWS Project is required in order to comply with permit conditions in the Consumptive Use Permits ("CUP") issued by the St. Johns River Water Management District ("SJRWMD" or "the District") for the Sanford Plant. Those permit conditions are intended to preserve Florida's groundwater, which is an important environmental resource. The SJRWMD adopted a policy in 2000 that, upon permit renewal, a user of the District's water is required to use the lowest quality of water that is technically, environmentally and economically feasible for its needs. This policy was implemented for the Sanford Plant in the current CUP, which requires use of water from the Sanford Cooling Pond as the LQWS for plant consumptive water use. The LQWS project at Sanford Plant is currently operational.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

For 2020, the water treatment system operator will bill FPL according to the cost of running the system, chemicals included, based on amount of water processed from the cooling pond.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are estimated to be $107,675, which is $48,325 or 31.0% lower than previously projected. The variance is primarily due to a capital purchase of reverse osmosis membranes/ultra-filtration modules which resulted in reductions to O&M.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $102,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CWA 316(b) Phase II Rule

Project No: 28

Project Description:

The final rule entitled, "National Pollutant Discharge Elimination System - Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities" (the 316(b) Rule and formerly the CWA 316(b) Phase II Rule), which became effective October 14, 2014, and is found in 40 CFR Parts 122 and 125, implements section 316(b) of the Clean Water Act ("CWA") for existing power plants. The 316(b) Rule is applicable to all power plants and other manufacturing that employ a cooling water intake structure and that withdraw two million gallons per day or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans or other Waters of the United States for cooling purposes. The 316(b) Rule established national requirements applicable to, and that reflect, the best technology available ("BTA") for the location, design, construction and capacity of, existing cooling water intake structures to minimize adverse environmental impacts. The DEP adopted the 316(b) Rule on June 24, 2015 and is implementing it at the following FPL facilities: Cape Canaveral Energy Center (CCEC), Ft. Myers Plant (PFM), Dania Beach Energy Center (DBEC, former Lauderdale Plant), Port Everglades Energy Center (PEEC), Riviera Beach Energy Center (RBEC), Sanford Plant (PSN), Martin Plant (PMR), Manatee Plant (PMT), and St. Lucie Plant (PSL). Plant Scherer is also regulated by the 316(b) Rule through the Georgia EPD.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

In 2020, work was conducted by consultants on reports required by the 316(b) Rule to determine the appropriate BTA for minimizing impingement mortality and entrainment at all of FPL's facilities employing once-through cooling water systems. This work will continue through the 2021 timeframe. CWA 316(b) compliance reports were submitted for the DBEC, PEEC, RBEC, and PFM, as part of the NPDES permit renewal process.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are estimated to be $1,068,913, which is $113,051 or 11.8% higher than previously projected. The variance is primarily due to contractor work associated with required studies for Fort Myers, Cape Canaveral, and St. Lucie plants being moved from 2019 into 2020 in order to prioritize the completion of studies associated with other facilities that had earlier permit application deadlines.

Capital - Project revenue requirements are estimated to be $77,810, which is $217,305 or 74.0% lower than previously projected. This is primarily a result of the cancellation of the Cape Canaveral Horseshoe Crab Return System Project. Based on the success of the horseshoe crab barrier installed in 2017, the Florida Department of Environmental Protection and the Florida Fish and Wildlife Conservation Commission agreed that the construction of a horseshoe crab return system is no longer required.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $504,217.

Capital - Estimated project revenue requirements for the projection period are $76,528.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Selective Catalytic Reduction Systems ("SCR") Consumables

Project No. 29

Project Description:

The Manatee Unit 3 and Martin Plant Unit 8 Expansion Project Final Orders of Certification under the Florida Power Plant Siting Act, and the PSD Air Construction Permit emission specifications, require the installation of SCRs for the control of NOx emissions. The DEP made the determination that the SCR system is considered Best Available Control Technology ("BACT") for these types of units, with concurrence from the EPA. The operation of the SCRs caused FPL to incur O&M costs for certain products that are consumed in the SCRs and for required Risk Management Plans ("RMP") and training. SCR components include anhydrous ammonia, analyzers, calibration gases, replacement catalyst, and equipment wear parts requiring periodic replacement.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Manatee Unit 3 and Martin Unit 8 completed the required 5 year Process Hazard Analysis, 3 year Compliance Audit, and annual training as required.

Required calibration of Martin Plant Unit 8 SCR system instrument and controls was performed. The Martin Plant Unit 8 HRSG Anhydrous Ammonia Blower Injection Skid Auto Shutoff Valve was replaced. Additionally, anhydrous ammonia is purchased as needed throughout the year.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are $105,721 or 19.9% higher than previously projected. The variance is primarily due to deferring ammonia system work at Manatee Plant Unit 3 from 2019 to 2020.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $466,664.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Clean Air Interstate Rule ("CAIR") Compliance

Project No. 31

Project Description:

In response to the EPA's Clean Air Interstate Rule ("CAIR"), FPL initiated the CAIR Project to implement strategies to comply with Annual and Ozone Season NOx and SO_2 emissions requirements. The CAIR project has included a consultant study of FPL's control and allowance management options, an engineering study conducted for the reliable cycling of the 800 MW units (Martin Plant Units 1 and 2, Manatee Plant Units 1 and 2), the construction and operation of SCRs on St. Johns River Power Park ("SJRPP") Units 1 and 2, the construction and operation of the scrubber and SCR for Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. On December 3, 2008, in addition to the EPA's CAIR requirements, Georgia EPD promulgated the GA Multi-Pollutant rule also requiring installation of an SCR and a Scrubber on Scherer Unit 4.

SJRPP was retired January 5, 2018 and Martin Plant Units 1 and 2 were retired in December of 2018.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

2020 O&M activities associated with the 800MW cycling project were primarily related to water demineralization and the use of chemicals for treatment of biological fouling of condenser tubes at Manatee Plant Units 1 and 2. Project O&M at Scherer includes routine maintenance of the SCR and scrubber and associated limestone sorbent costs for removal of SO_2 and ammonia costs for control of NOx.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $3,833,259, which is $1,808,686 or 32.1% lower than previously projected. The variance is primarily due to lower than projected unit dispatch of Scherer Unit 4, which resulted in lower consumption of ammonia and limestone in the treatment process.

Capital - Project revenue requirements are estimated to be $45,144,078, which is $375,052 or 1.0% lower than previously projected.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $3,891,050.

Capital - Estimated project revenue requirements for the projection period are $44,511,165.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: MATS Project

Project No. 33

Project Description:

The Clean Air Mercury Rule ("CAMR") was promulgated by the EPA on March 15, 2005, imposing nationwide standards of performance for mercury ("Hg") emissions from existing and new coal-fired electric utility steam generating units. The CAMR is designed to reduce emissions of Hg through implementation of coal-fired generating unit Hg controls. In addition, CAMR requires the installation of Hg Continuous Emission Monitoring Systems ("HgCEMS") to monitor compliance with the emission requirements. In response to a court decision vacating the CAMR, the EPA promulgated a final Mercury and Air Toxics Standard ("MATS") rule that addressed toxic metal (including Hg) and acid gas emissions from coal and oil-fired steam electric generating units. FPL's coal-fired Scherer plant is subject to this replacement rule and costs for compliance continue to be recovered under this project. On June 29, 2015 the Supreme Court issued an opinion remanding the MATS rule back to the D.C. Circuit Court of Appeals deciding that the EPA could ignore costs when deciding to regulate power plants. On April 16th 2020, EPA responded by publishing a revised supplemental finding. The revised supplemental finding revoked the appropriate and necessary finding but kept the existing mercury standards in place.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

For Plant Scherer, operation for the baghouse and sorbent injection system continues per the requirements of the State of Georgia Multi Pollutant Rule and MATS.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $1,888,540, which is $759,795 or 28.7% lower than previously projected. The variance is primarily due to lower than projected unit dispatch of Scherer Unit 4, which resulted in lower consumption of powdered activated carbon in the treatment process.

Capital - Project revenue requirements are estimated to be $9,423,322, which is $169,770 or 2.0% lower than previously projected.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $2,420,782.

Capital - Estimated project revenue requirements for the projection period are $9,252,605.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Cooling Water System Inspection and Maintenance

Project No. 34

Project Description:

The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project is to inspect and, as necessary, maintain the cooling water system (the "Cooling System") at FPL's St. Lucie Nuclear Power Plant, such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the Federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions imposed pursuant to a Biological Opinion ("BO") that was issued by the National Marine Fisheries Service ("NMFS") pursuant to Section 7 of the Endangered Species Act. The NMFS finalized the BO on March 24, 2016. FPL is currently working with NMFS to develop an acceptable cooling system turtle excluder device or alternatives, as required by the BO.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

The project is currently on hold while the NMFS is developing an updated BO.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $354,911, which is $100,190, or 22.0% lower than previously projected. The variance is due to the original projection assuming a January 2020 in-service date for $4.5 million. The current projection assumes an in-service date in 2021.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $357,304.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Plant Water System

Project No. 35

Project Description:

The Martin Plant Drinking Water System is required to comply with the requirements of the DEP's rules for drinking water systems. The DEP determined the system must be brought into compliance with newly imposed drinking water rules for trihalomethanes and Haleo Acetic Acid. These include nano-filtration, air stripping, carbon and multimedia filtration.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Martin completed the conversion to the Village of Indiantown as the supplier of the potable water for the entire site.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are $10,492 more than the projection of $0. While Martin Units 1 and 2 were shut down in 2018, the drinking water system associated with Units 1 and 2 remained in operation to supply drinking water to the entire Martin plant site. In its ECRC Projections filing, FPL projected costs for shutdown of the existing system and conversion to local potable water supply would be completed in 2019. As a result of unanticipated delays in engineering and permitting, the project was not completed until May 8, 2020, resulting in an unplanned impact to 2020 expenditures. The drinking water plant has been shut down and drinking water for the site is now supplied by the Village of Indiantown.

Capital - Project revenue requirements are estimated to be $20,188, which is $178 or 1.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $19,807.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low Level Radioactive Waste

Project No. 36

Project Description:

The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste ("LLW") such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. On June 30, 2008, the Barnwell facility ceased accepting LLW from FPL. The objective of this project is to provide a LLW storage facility at the St. Lucie and Turkey Point plants with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5-year period. This will allow continued uninterrupted operation of the St. Lucie and Turkey Point nuclear units until an alternate solution becomes available. The LLW on site storage facilities at St. Lucie and Turkey Point also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $1,653,138, which is $14,677 or 1.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $1,622,516.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: DeSoto Next Generation Solar Energy Center

Project No. 37

Project Description:

The DeSoto Next Generation Solar Energy Center ("DeSoto Solar") project is a zero greenhouse gas emitting renewable generation project, which, on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The DeSoto Solar project is a 25 MW solar photovoltaic ("PV") generating facility, which converts sunlight directly into electric power utilizing tracking arrays that are designed to follow the sun as it traverses through the sky. In addition, the system includes electrical equipment necessary to convert the power from direct current to alternating current to connect the system to the FPL grid. Ongoing operation and maintenance expenses include repair and replacement of PV system components and support equipment and facilities by FPL personnel and vegetation management of land adjacent to the panels.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Several direct current field walk downs and necessary repairs were performed this year, in order to ensure improved efficiency to current performance. Preventative maintenance work including inverter cleanings, inverter condition assessments, and switchgear maintenance was performed according to site prescribed maintenance cycle. Site personnel continue to perform required maintenance activities including replacement of components as necessary.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M Project expenditures are 670,971, which is $169,545 or 20.2% lower than previously projected. The variance is primarily due to less full-time employee support to the Desoto site. Additionally, the forecast included costs for previously completed maintenance on a container breaker. Lastly, field work that was charged to the Desoto site in 2019 should have been charged to the Citrus site. This error was found in a 2019 variance review and was corrected in May 2020.

Capital - Project revenue requirements are estimated to be $11,943,760, which is $258,944 or 2.0% lower than previously projected.

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PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $546,286.

Capital - Estimated project revenue requirements for the projection period are $11,450,670.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Space Coast Next Generation Solar Energy Center

Project No. 38

Project Description:

The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Space Coast Solar project is a 10 MW PV generating facility which converts sunlight directly into electric power. The facility utilizes a fixed array and uses solar PV panels, support structures, and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid. Ongoing operation and maintenance expenses include repair and replacement of PV system components and support equipment and facilities by FPL personnel and vegetation management of land adjacent to the panels.

The Space Coast project also included building a 900 kW solar PV facility at the Kennedy Space Center ("KSC") industrial area. The KSC solar site was built and is operated and maintained by FPL as compensation for the lease of the land for the Space Coast Solar site which is located on KSC property.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Quarterly O&M reports are submitted to NASA in accordance with the lease agreement between NASA and FPL. Support personnel continue to perform required maintenance activities including replacement of components as necessary for Space Coast/Kennedy Solar ECRC sites.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are estimated to be $268,593, which is $7,474 or 2.7% lower than previously projected.

Capital - Project revenue requirements are estimated to be $5,561,296, which is $122,087 or 2.0% lower than previously projected.

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PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $268,106.

Capital - Estimated project revenue requirements for the projection period are $5,342,024.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Next Generation Solar Energy Center (Solar Thermal)

Project No. 39

Project Description:

On August 4, 2008, the Commission found, in Order Number PSC-08-0491-PAA-EI, that the Martin Next Generation Solar Energy Center ("Martin Solar") project was eligible for recovery through the ECRC pursuant to House Bill 7135. The Martin Solar project is a 75 MW solar thermal steam generating facility which is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined cycle power plant. The steam supplied by Martin Solar is used to supplement the steam currently generated by the heat recovery steam generators. The project involved the installation of parabolic trough solar collectors that concentrate solar radiation on heat collection elements and track the sun to maintain the optimum angle to collect solar radiation. These heat collection elements contain a heat transfer fluid ("HTF") that is heated by the concentrated solar radiation and is then circulated to heat exchangers that will produce steam, which is routed to the existing Martin Unit 8 heat recovery steam generators for use in generating a design rating of 75 MW of electricity from the Martin Unit 8 Steam Turbine Generator.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

2020 to date, Martin Solar accomplishments include routine repairs to solar loops, including replacement of heat collection elements and parabolic mirrors, oil changes on the solar array hydraulic drives, and 10-year vessel integrity inspections on solar heat exchangers. Other accomplishments include the installation of high temperature flowmeters on several heat collection loops that provide data for maintaining high efficiency, various preventative maintenance jobs completed in the solar field and power block and use of drone thermography to perform field inspections.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $4,747,474, which is $1,622 or 0.03% higher than previously projected.

Capital - Project revenue requirements are estimated to be $34,080,447, which is $570,378 or 2.0% lower than previously projected.

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Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $4,065,551.

Capital - Estimated project revenue requirements for the projection period are $33,133,292.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Greenhouse Gas Reduction Program

Project No. 40

Project Description:

The purpose of FPL's Electric Utility Greenhouse Gas ("GHG") Reduction Program is to comply with the EPA's policies that require reductions in emissions of GHGs from electric generating units and mandatory reporting of GHG emissions. The EPA's Mandatory GHG Reporting Rule requires electric utilities to record emissions of GHGs, primarily CO_2 from the combustion of fossil fuels, and report actual data in the subsequent year. FPL was required to begin reporting GHGs emitted from its fossil generating units annually starting in 2011 for calendar year 2010 and to report every year thereafter. The EPA's performance standards for reductions of GHG emissions have been proposed as a final rule that addresses only efficiency improvements on coal-fired electric utility steam generating units. While the proposed rule has been challenged, FPL does not currently anticipate any additional costs for compliance with the new GHG rule.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $0.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - There are no projected costs.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Temporary Heating System ("MTHS")

Project No. 41

Project Description:

FPL is subject to specific and continuing legal requirements to provide warm water refuges for the threatened manatee at its Port Everglades, Ft. Myers, Lauderdale, Riviera, and Cape Canaveral plants.

FPL's installation of a MTHS at each site was implemented to provide warm water until each site completed the planned modernization of the existing power generation units and the warm water flow from the generating unit cooling water returned. The Power Plant Siting Act Conditions of Certification require additional environmental and biological monitoring associated with the operation of the heaters during and following plant shut-downs due to the modernizations. The modernization projects have been completed at Cape Canaveral, Port Everglades and Riviera, with Fort Lauderdale being modernized (Dania Beach Clean Energy Center) during the 2018-2022 time frame. For Cape Canaveral, the heating system remained in place to serve as an emergency backup in the future in case the entire Unit 3 power block needs to shut down during future manatee seasons. Due to requirements of the U.S. Fish and Wildlife Service to reduce the possibility of impinging dead or severely compromised manatees on the Cape Canaveral intake screens, Cape Canaveral relocated the permanent manatee heating area farther from the plant intakes. Fort Myers is also installing a permanent MTHS due to its "northern" location and the probability of reduced plant operation in the future.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

The MTHS at the Lauderdale Plant and Fort Myers Plant are installed and will run as needed during manatee seasons.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $152,070, which is $43,830 or 22.4% lower than previously projected. The variance is primarily due to lower than projected costs related to required monitoring at the Dania Beach Energy Center.

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PROJECT DESCRIPTION AND PROGRESS

Capital - Project revenue requirements are estimated to be $3,338,462, which is $101,686, or 3.0% higher than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $195,900.

Capital - Estimated project revenue requirements for the projection period are $3,171,174.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Turkey Point Cooling Canal Monitoring Plan ("TPCCMP")

Project No. 42

Project Description:

Pursuant to Conditions IX and X of the DEP's Final Order Approving Site Certification, FPL submitted a revised Cooling Canal Monitoring Plan to the South Florida Water Management District ("SFWMD"). After receiving input from the SFWMD as well as the DEP and Miami-Dade County Department of Environmental Resource Management ("MDC DERM"), the Revised Plan was finalized on October 14, 2009. The objective of FPL's TPCCMP Project is to implement the Conditions of Certification IX and X.

Based on the data FPL had collected pursuant to the Revised Plan, the DEP, in consultation with the SFWMD and the MDC DERM issued a final Administrative Order ("AO") on December 23, 2014. The AO directed FPL to achieve a substantial reduction in Cooling Canal System ("CCS") salinity within four years and identified a series of potential measures that FPL could include in the Salinity Management Plan ("SMP") outlining how it would achieve the reductions. The AO was challenged by several parties. In October 2015, the MDC DERM entered into a Consent Agreement ("CA") with FPL. Following challenges to the AO, the DEP issued a Final Administrative Order on April 21, 2016, and on April 25, 2016, it issued a Notice of Violation ("NOV") regarding the hypersaline groundwater to the west of the CCS and a Warning letter identifying issues related to water quality in a few deep artificial channels to the east and south of the CCS. The NOV directed FPL to enter into a Consent Order ("CO") to, at a minimum, remediate the CCS contribution to the hypersaline plume, reduce the size of the hypersaline plume, and prevent future harm to waters of the State. The CO was executed between FPL and the DEP on June 20, 2016. On August 15, 2016 the MDC DERM entered into an addendum to the CA with FPL ("CAA"), which requires FPL to undertake additional activities to address releases of groundwater into deep artificial channels on the east side of the CCS.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

FPL continues to move forward with compliance and implementation of actions required under the CO, CA and CAA. FPL completed fill and restoration of the Turtle Point and Turning Basin canals in 2020. Additionally, FPL has continued operation of the recovery well system ("RWS") consisting of 10

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extraction wells required by the CO and CA. The RWS extracts up to 15 million gallons per day of hypersaline groundwater from the Biscayne aquifer and safely disposes it in an underground injection control ("UIC") well. After the first year of operations and based on the results of the first Continuous Surface Electromagnetic Mapping survey, the RWS reduced the hypersaline plume volume by 22%. The results indicate the RWS is functioning as designed and is on track to achieve the objectives outlined in the CO. FPL also continued implementing strategies under the Nutrient Management Plan required by the CO to reduce nutrients in the CCS surface waters. The second phase of seagrass planting was completed in early 2020, and growth has been observed. FPL also undertook an extensive vegetation management plan to remove exotic vegetation from the canal berms, which is a source of nutrients in the CCS. These efforts will assist in reducing nutrients in the system and mitigate the magnitude of algae blooms. With regard to salinity management, FPL installed an additional freshening well, that was previously permitted, to maximize achievement of the 14 mgd freshening capacity and installed infrastructure to redirect excess Floridian water from Turkey Point's process water allocation to the CCS for freshening. Additionally, FPL submitted a Supplemental SMP outlining additional measures FPL intends to undertake to achieve the CCS salinity threshold.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are estimated to be $19,694,511, which is $1,059,191 or 5.7% higher than previously projected.

Capital - Project revenue requirements are estimated to be $6,058,054, which is $404,215, or 6.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $9,746,110.

Capital - Estimated project revenue requirements for the projection period are $6,807,724.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Plant Barley Barber Swamp Iron Mitigation Project

Project No. 44

Project Description:

Martin Plant Barley Barber Swamp Iron Mitigation Project was installed in 2011. The project included the installation of complete siphon systems to mitigate iron discharges in the Barley Barber Swamp. The systems, which use cooling pond water (low iron) to hydrate the swamp, are required by permit.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $14,606 which is $131 or 1.0% lower than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $14,342.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: 800MW Unit Electrostatic Precipitator ("ESP") Project

Project No. 45

Project Description:

On December 21, 2011, the EPA issued the final MATS rule as required under Section 112 of the Clean Air Act for regulation of Hazardous Air Pollutants. This has the effect of requiring ESPs for the 800 MW oil-fired units (Martin Plant Units 1 and 2, Manatee Plant Units 1 and 2) to meet the established numerical emission limits for particulate material when combusting fuel oil. ESPs are the most cost-effective form of particulate emission control for the 800 MW oil-fired units. As to the final MATS rule's limits on acid gasses, FPL uses the compliance option of limiting the moisture content of the oil it burns in those units through its specifications for fuel oil procurement. To comply with the MATS Rule, FPL installed ESPs on Manatee Units 1 and 2 and Martin Units 1 and 2.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

The Manatee Plant systems will continue to operate until the units are retired, with O&M costs for payroll, materials, and contractors. These costs are associated with inspections, ash disposal, preventative maintenance, and repairs needed to operate and maintain the system. Martin Plant Units 1 and 2, and their associated ESP's, were retired in 2018.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $154,969, which is $105,720 or 40.6% lower than previously projected. The variance is primarily due to a shift in the outage schedule causing the majority of the work planned on Manatee Unit 1 in March to be postponed until 2021.

Capital - Project revenue requirements are estimated to be $18,821,748, which is $150,838, or 1.0% lower than previously projected.

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Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $264,099.

Capital - Estimated project revenue requirements for the projection period are $18,500,095.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: NPDES Permit Renewal Requirements

Project No. 47

Project Description:

The Federal Clean Water Act requires all point source discharges into navigable waters from industrial facilities to obtain permits under the NPDES program. See 33 U.S.C. Section 1342. Pursuant to the EPA's delegation of authority, the DEP implements the NPDES permitting program in Florida. Affected facilities are required to apply for renewal of the 5-year-duration NPDES permits prior to their expiration.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

The 2019 pilot study for the use of chlorine dioxide to replace sodium hypochlorite (bleach) as a biocide in the St. Lucie plant's cooling water system was effective and PSL received a minor permit revision from FDEP on May 21, 2020 to use chlorine dioxide as an approved biocide.

The Martin Plant NPDES Permit was not renewed in 2019 as was anticipated. The DEP has informed FPL that the new permit is now expected to be issued in 2021 and will contain a discharge limit for a new parameter, total ammonia as nitrogen ("TAN"). The DEP is aware the Martin Plant will not be able to meet the TAN limit for several of the facility's wastewater discharges without an administrative solution, such as a site-specific alternative criterion, or installation of a treatment system. FPL currently anticipates that the DEP will attach an Administrative Order to the NPDES Permit requiring the Martin Plant to achieve compliance with the TAN limit within 48 months of the permit issuance. A Plan of Study, which must be approved by DEP, will identify sources of ammonia in the cooling pond as well as the effluent from the cooling pond. FPL will conduct a feasibility study pursuant to a DEP-approved plan. Options for achieving the TAN limit will be ranked based on equal weighing of technical and economic feasibility. The highest ranking solution, which could be a technical solution, a regulatory moderating petition, or some combination thereof, must be implemented.

Also during 2020, FPL conducted Whole Effluent Toxicity Testing at its Cape Canaveral, Ft. Myers, Riviera, Port Everglades, and St. Lucie plants.

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Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are estimated to be $93,797, which is $12,643 or 15.6% higher than previously projected.

Capital – Project revenue requirements are estimated to be $53,039, which is $25,372 or 92.0% higher than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $80,996.

Capital - Estimated project revenue requirements for the projection period are $301,421.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Industrial Boiler MACT Project

Project No. 48

Project Description:

40 CFR Part 63 Subpart JJJJJ Final Rule for National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers was published on March 21, 2011. 40 CFR Part 63 Subpart DDDDD Final Rule for National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters was published on November 20, 2015. FPL must complete energy audits, inspections and boiler tune-ups as well as comply with recordkeeping requirements for boilers and heaters that are subject to these rules.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

FPL's Industrial Boiler MACT project includes required boiler tuning for the affected units and one-time performance of a site energy audit for each site. FPL has performed required boiler tunings at FPL's Martin Fuel Oil Terminal and the auxiliary boilers at its Fort Myers, Lauderdale, Martin, and West County power generation facilities. The auxiliary boilers at Fort Myers, Lauderdale and at FPL's Martin Fuel Oil Terminal have been retired.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $32,668, which is $168 or 0.5% higher than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $65,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Thermal Discharge Standards Project

Project No. 49

Project Description:

FPL power plants with once-through cooling water systems that were built before July 1, 1972, must meet a "narrative" thermal standard found in Chapter 62-302.520(1) (a)-(c) F.A.C.

Facilities that cannot meet the DEP narrative standard for thermal discharges may apply for a "variance" (i.e. less stringent standards) under Section 316(a) of the Federal Clean Water Act. Section 316(a) ensures that thermal effluent limitations will assure protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife and provides that thermal dischargers can be granted less stringent alternate thermal limits than those imposed by a state program if the discharger can demonstrate that the current effluent limitations, based on water quality standards, are more stringent than necessary to protect the aquatic organisms in the receiving water body.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

There are no projected costs.

Project Projections:

(January 1, 2021 to December 31, 2021)

There are no projected costs.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Steam Electric Effluent Limitation Guidelines Revised Rule

Project No. 50

Project Description:

Title 40 Code of Federal Regulations Part 423, which was promulgated under the authority of the Federal Clean Water Act, limits the discharge of pollutants into navigable waters and into publicly owned treatment works by existing and new sources of steam electric power plants. The previous version of the Steam Electric Effluent Limitation Guidelines ("ELG") Rule was published in the Federal Register on November 19, 1982. The renewed final ELG rule was promulgated and became effective on January 4, 2016. The ELG Rule requires facilities to be in compliance as soon as possible, but no later than 2023. In 2017 the EPA published a revised ELG Rule that postponed the earliest implementation of the ELG Rule to 2020. In May 2018 the EPA published a new plan for implementation of the ELG Rule, which could result in less stringent requirements. The EPA is reviewing the rule to determine if the strict requirements for treating or eliminating certain waste streams are justified. The draft ELG Rule was published on November 22, 2019. A new final rule is expected to be in place by 2020-2021.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Georgia Power, the operating agent for Plant Scherer, continued to conduct studies evaluating technologies to determine the costs for various methods of complying with the proposed ELG Rule. Activities necessary to achieve compliance will continue as the revised Rule will be issued in 2020-2021, which is currently the earliest compliance date for the Rule.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are $4,608 versus an original estimate of $0. The variance is primarily due to study related costs, which were originally anticipated to be capitalized. Delays associated with the issuance of a final, revised Steam Electric Effluent Limitations Guidelines Rule delayed capitalization.

Capital – Project revenue requirements are estimated to be $99,788, which is $44,478 or 31.0% lower than previously projected.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $385,191.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Gopher Tortoise Relocation Project

Project No. 51

Project Description:

The gopher tortoise (*Gopherus polyphemus*) is a state-designated threatened species, per Rule 68A-27.003(1)(d)3, F.A.C. Gopher tortoises have been creating burrows in the cooling pond embankments at FPL's Martin, Manatee and Sanford plants over time, as well as in the oil tank farm embankments at Martin and Manatee plants. Gopher tortoise burrows must be inspected and then filled as necessary to ensure the integrity of the embankments. Filling burrows means that affected gopher tortoises must be relocated. In 2008, the FWC provided new gopher tortoise guidelines that have changed the permitting process for relocations. An authorized gopher tortoise agent is now required to conduct surveys and perform relocations, and all tortoises now must be sent to a recipient site.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Gopher tortoise relocations have taken place at the Martin plant and are currently in progress at the Manatee Plant. FPL will continue to monitor gopher tortoise activity throughout the year at Sanford, Martin, and Manatee plants' cooling ponds and the Manatee fuel oil storage terminal.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $28,732, which is $3,083 or 12.0% higher than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projected period are $39,523.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Numeric Nutrient Criteria

Project No. 52

Project Description:

The DEP drafted a Numeric Nutrient Criteria ("NNC") rule on June 28, 2013, and the EPA accepted the state numeric and narrative standards for freshwaters. On September 26, 2013, the EPA accepted the DEP's NNC standards for Florida's estuaries. The Environmental Regulation Commission for the State of Florida adopted the proposed NNC for estuarine and coastal waters on December 1, 2014. The DEP submitted the final coastal criteria to the EPA in May of 2015. The DEP's NNC rule has been implemented through NPDES Industrial Waste Water permit renewals to achieve the reduction of total nitrogen and total phosphorus discharges and loading in Florida freshwaters, estuarine and coastal waters.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M -There are no projected costs.

Project Projections:

(January 1, 2021 to December 31, 2021)

There are no projected costs for the projection period.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Coal Combustion Residuals – SJRPP and Scherer

Project No: 54

Project Description:

The final rule entitled, "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities," which became effective October 19, 2015 and is found in 40 CFR Parts 257 and 261, regulates the disposal of coal combustion residuals ("CCR") generated from the combustion of coal in new and existing impoundments and landfills at electric utilities and independent power producers. Subsequent amendments, court decisions and the WIIN Act have modified the 2015 requirements by extending deadlines for closure, additional beneficial use, and approval of state CCR permitting programs. The Georgia Environmental Protection Division's ("Georgia EPD") adoption of the CCR rule at 391-3-4-.10 was approved by USEPA effective February 20, 2020. The Georgia EPD rule establishes a permit program for CCR impoundments and landfills in addition to the Federal CCR criteria.

The CCR rule established requirements for location, design, operation, safety, public disclosure and closure of CCR impoundments and landfills at electric utilities. Existing facilities that fail to meet the criteria including the location requirements or indications of groundwater impacts are required to cease receiving CCR in 6 months and initiate closure of the disposal unit. The location criteria include a requirement for an unlined surface impoundments to be located at least 5 feet above the uppermost aquifer and no hydraulic connection between the base of the unit and the aquifer.

The rule set specific schedules for implementation of each of the performance requirements including a groundwater monitoring system and detection monitoring plan, inspection, demonstration of compliance with location restrictions or no groundwater contact, development of the CCR unit closure plan and Professional Engineer inspections. While SJRPP was retired on January 5, 2018, the CCR rule compliance requirements for ash which was previously produced at the plant continues. Unlined impoundments such as the Scherer ash pond are required to cease receipt of CCR by October 31, 2020 and initiate closure.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

SJRPP has completed evaluation of the landfill and determined that it is an unlined unit that meets the location restrictions. Additional wells have been installed to meet the groundwater monitoring requirements. Georgia Power, as the Plant Scherer operating partner, has completed evaluation of the ash

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

impoundment and determined that it is an unlined unit that meets the location description. Groundwater monitoring wells have been installed and initial background monitoring has begun. Ash water management facilities have been completed and placed in service. Feasibility studies are being conducted to determine the best approach to physical closure. Future lined landfill space for replacement capacity is under construction to replace the existing impoundment.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project expenditures are estimated to be $0, which is $1,600,768 or 100.0% lower than previously projected. The variance is due to costs associated with the replacement of a wet bottom ash system with a dry bottom ash system that should not have been included in the 2020 Projections filing.

Capital - Project revenue requirements are estimated to be $9,951,398, which is $547,184, or 6.0% higher than previously projected.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M - Estimated project costs for the projection period are $0.

Capital - Estimated project revenue requirements for the projection period are $11,297,162.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Solar Site Avian Monitoring and Reporting

Project No. 55

Project Description:

Pursuant to the Development Review Committee Order DR-17-04 ("Order DR-17-04") issued by the Alachua Department of Growth Management ("Alachua DGM") on February 16, 2017, FPL is required to conduct avian mortality monitoring and report on the results of that monitoring as a permit condition for the Horizon Solar Energy Center ("HSEC"). FPL will be monitoring and reporting on avian mortality at FPL's existing DeSoto solar photovoltaic ("PV") facility ("DeSoto"), utilizing a protocol for avian monitoring at solar facilities that was developed in conjunction with the FWC. In order to accommodate the Alachua DGM's desire for prompt results, FPL recommended that monitoring be conducted at DeSoto (an existing universal solar facility) because construction of HSEC had not been completed at the time the permit condition was imposed. Using a fully operational site helped FPL and FWC create the avian solar protocol and allowed FPL to conduct a necessary trial in 2017 for implementing the protocol. The Alachua DGM agreed that the data from DeSoto would be representative of future universal solar PV facilities located in Alachua County and required the monitoring be conducted at DeSoto as part of the Order DR-17-04.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

The monitoring at the DeSoto facility was competed in 2019 and the final report was submitted in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $0.

Project Projections:

(January 1, 2021 to December 31, 2021)

There are no projected costs for the projection period.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Power Plant Intake Protected Species Project

Project No. 123

Project Description:

Under the United States Endangered Species Act ("ESA") (16 U.S.C. § 1531 et seq.), FPL is required to avoid the "take" of species listed as endangered or threatened. FPL is also required to avoid the "take" of a species listed as threatened under Chapter 68A-27 of the Florida Administrative Code. In the event FPL "takes" a species without authorization provided by the appropriate federal regulatory authority, it constitutes an unauthorized take. In the event of an unauthorized take, the appropriate federal and state wildlife agencies may require FPL to develop solutions that avoid interaction between listed species and intake structures, or apply for an incidental take permit that would require FPL to minimize or mitigate interaction between listed species and intake structures. When solutions are developed, FPL is required to implement the solution(s) at the designated facilities.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

FPL has engaged a consultant for work at the Fort Myers Plant related to the smalltooth sawfish and for work at the Cape Canaveral Energy Center related to the Florida manatee. The consultant reviewed site plans and operational details to provide options to be further investigated at the Fort Myers Plant. The consultant is also reviewing potential options for the Cape Canaveral Energy Center.

Project Costs:

(January 1, 2020 to December 31, 2020)

O&M - Project costs are estimated to be $34,000. This is a new project.

Project Projections:

(January 1, 2021 to December 31, 2021)

O&M – Estimated costs are projected to be $100,000 for the projection period.

Capital – Project revenue requirements are projected to be $7,364.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-6P

JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
RATE CLASS	Avg 12 CP Load Factor at Meter (%) [b]	Avg 12 GCP Load Factor at Meter (%) [c]	Projected Sales at Meter (KWH) [d]	Projected Avg 12 CP at Meter (KW) [e]	Projected Avg 12 GCP at Meter (KW) [f]	Demand Loss Expansion Factor [g]	Energy Loss Expansion Factor [h]	Projected Sales at Generation (KWH) [i]	Projected Avg 12 CP at Generation (kW) [j]	Projected Avg 12 GCP Demand at Generation (kW) [k]	Percentage of KWH Sales at Generation (%) [l]	Percentage of 12 CP Demand at Generation (%) [m]	Percentage of 12 GCP Demand at Generation (%) [n]
RS1/RTR1	61.756%	59.072%	59,729,073,564	11,040,784	11,542,423	1.06227433	1.04681581	62,525,338,592	11,728,341	12,261,220	53.46670%	57.14077%	57.90415%
GS1/GST1	61.000%	59.662%	6,506,168,667	1,217,559	1,244,876	1.06227433	1.04681581	6,810,760,231	1,293,382	1,322,400	5.82402%	6.30139%	6.24509%
GSD1/GSDT1/HLFT1/GSD1-EV	70.568%	69.554%	27,339,372,990	4,422,592	4,487,060	1.06219494	1.04675521	28,617,631,124	4,697,655	4,766,132	24.47152%	22.88709%	22.50827%
OS2	154.701%	15.348%	9,166,365	676	6,818	1.03727996	1.02815396	9,424,434	702	7,072	0.00806%	0.00342%	0.03340%
GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	69.605%	66.528%	10,202,110,568	1,673,190	1,750,590	1.06138651	1.04617543	10,673,197,409	1,775,902	1,858,052	9.12687%	8.65224%	8.77473%
GSLD2/GSLDT2/CS2/CST2/HLFT3	84.453%	81.681%	2,700,592,177	365,038	377,429	1.05234833	1.03941858	2,807,045,699	384,147	397,187	2.40036%	1.87157%	1.87573%
GSLD3/GSLDT3/CS3/CST3	83.597%	0%	259,242,549	35,401	0	1.02222729	1.01685659	263,612,494	36,188	0	0.22542%	0.17631%	0%
SST1T	84.075%	0%	92,787,905	12,598	0	1.02222729	1.01685659	94,351,993	12,879	0	0.08068%	0.06275%	0%
SST1D1/SST1D2/SST1D3	52.653%	14.380%	1,849,941	401	1,469	1.04514716	1.03665634	1,917,753	419	1,535	0.00164%	0.00204%	0.00725%
CILC D/CILC G	85.444%	84.136%	2,739,981,680	366,067	371,760	1.05216077	1.03935565	2,847,815,431	385,161	391,152	2.43523%	1.87651%	1.84723%
CILC T	93.078%	0%	1,470,591,289	180,360	0	1.02222729	1.01685659	1,495,380,442	184,369	0	1.27873%	0.89825%	0%
MET	76.794%	68.401%	80,325,996	11,941	13,406	1.03727996	1.02815396	82,587,491	12,386	13,906	0.07062%	0.06034%	0.06567%
OL1/SL1/SL1M/PL1	13,844.128%	48.912%	575,951,839	475	134,420	1.06227433	1.04681581	602,915,492	504	142,791	0.51557%	0.00246%	0.67434%
SL2/SL2M/GSCU1	96.257%	94.339%	105,664,172	12,531	12,786	1.06227433	1.04681581	110,610,926	13,312	13,582	0.09459%	0.06486%	0.06414%
Total			111,812,879,702	19,339,613	19,943,037			116,942,589,511	20,525,347	21,175,029	100.00000%	100.00000%	100.00000%

[b] Projected Avg 12 CP load factor based on 2017-2019 load research data and 2021 projections
[c] Projected Avg 12 GCP load factor based on 2017-2019 load research data and 2021 projections
[d] Projected KWH sales for the period January 2021 through December 2021
[e] Calculated: (Col 4)/(8,760 * Col 2)
[f] Calculated: (Col 4)/(8,760 * Col 3)
[g] Based on 2021 demand losses
[h] Based on 2021 energy losses
[i] Col 4 * Col 8
[j] Col 5 * Col 7
[k] Col 6 * Col 7
[l] Col 9 / Total for Col 9
[m] Col 10 / Total for Col 10
[n] Col 11 / Total for Col 11

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
TOTAL JURISDICTIONAL AMOUNT TO BE RECOVERED

FORM: 42-7P

JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE CLASS	Percentage of kWh Sales at Generation (%) [b]	Percentage of 12 CP Demand at Generation (%) [c]	Percentage of GCP Demand at Generation (%) [d]	Energy Related Cost ($) [e]	CP Demand Related Cost ($) [f]	GCP Demand Related Cost ($) [g]	Total Environmental Costs ($) [h]	Projected Sales at Meter (kWh) [i]	ECRC Factor (cents/kWh) [j]
RS1/RTR1	53.46670%	57.14077%	57.90415%	$14,353,647	$73,196,284	$1,443,014	$88,987,346	$59,729,073,564	0.149
GS1/GST1	5.82402%	6.30139%	6.24509%	$1,563,514	$8,071,965	$155,632	$9,790,408	$6,506,168,667	0.150
GSD1/GSDT1/HLFT1/GSD1-EV	24.47152%	22.88709%	22.50827%	$6,569,614	$29,317,948	$560,923	$36,450,906	$27,339,372,990	0.133
OS2	0.00806%	0.00342%	0.03340%	$2,164	$4,381	$832	$7,379	$9,166,365	0.080
GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	9.12687%	8.65224%	8.77473%	$2,450,195	$11,083,360	$218,673	$13,752,918	$10,202,110,568	0.135
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.40036%	1.87157%	1.87573%	$644,400	$2,397,452	$46,745	$3,089,385	$2,700,592,177	0.114
GSLD3/GSLDT3/CS3/CST3	0.22542%	0.17631%	0.00000%	$60,516	$225,848	$0	$286,465	$259,242,549	0.110
SST1T	0.08068%	0.06275%	0.00000%	$21,660	$80,378	$0	$102,074	$92,787,905	0.110
SST1D1/SST1D2/SST1D3	0.00164%	0.00204%	0.00725%	$440	$2,615	$181	$3,234	$1,849,941	0.175
CILC D/CILC G	2.43523%	1.87651%	1.84723%	$653,760	$2,403,780	$46,034	$3,104,412	$2,739,981,680	0.113
CILC T	1.27873%	0.89825%	0.00000%	$343,287	$1,150,642	$0	$1,494,635	$1,470,591,289	0.102
MET	0.07062%	0.06034%	0.06567%	$18,959	$77,301	$1,637	$97,911	$80,325,996	0.122
OL1/SL1/SL1M/PL1	0.51557%	0.00246%	0.67434%	$138,408	$3,145	$16,805	$159,022	$575,951,839	0.027
SL2/SL2M/GSCU1	0.09459%	0.06486%	0.06414%	$25,392	$83,080	$1,598	$110,115	$105,664,172	0.104
TOTAL				$26,845,958	$128,098,178	$2,492,074	$157,436,210	111,812,879,702	0.141

[b] From Form 42-6P, Col 12
[c] From Form 42-6P, Col 13
[d] From Form 42-6P, Col 14
[e] Total Energy $ from Form 42-1P, Line 5
[f] Total CP Demand $ from Form 42-1P, Line 5
[g] Total GCP Demand $ from Form 42-1P, Line 5
[h] Col 5 + Col 6 + Col 7
[i] Projected kWh sales for the period January 2021 through December 2021
[j] Col 8 / Col 9

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

FORM 42-8P

FORECASTED 2021
CAPITAL STRUCTURE AND COST RATES [a]

Equity @ 10.55%

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	14,422,813,072	30.730%	3.86%	1.1856%	1.19%
SHORT_TERM_DEBT	699,416,366	1.490%	0.75%	0.0112%	0.01%
PREFERRED_STOCK	0	0.000%	0.00%	0.0000%	0.00%
CUSTOMER_DEPOSITS	417,807,033	0.890%	2.04%	0.0182%	0.02%
COMMON_EQUITY [b]	22,313,469,981	47.543%	10.55%	5.0158%	6.65%
DEFERRED_INCOME_TAX	8,285,651,758	17.654%	0.00%	0.0000%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.0000%	0.00%
WEIGHTED COST	794,379,656	1.693%	7.92%	0.1341%	0.17%
TOTAL	$46,933,537,866	100.00%		6.3648%	8.03%

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

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$14,422,813,072	39.26%	3.858%	1.515%	1.515%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	22,313,469,981	60.74%	10.550%	6.408%	8.490%
TOTAL	$36,736,283,053	100.00%		7.923%	10.005%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.1856%
SHORT TERM DEBT	0.0112%
CUSTOMER DEPOSITS	0.0182%
TAX CREDITS -WEIGHTED	0.0256%
TOTAL DEBT	**1.2406%**

EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	5.0158%
TAX CREDITS -WEIGHTED	0.1085%
TOTAL EQUITY	**5.1242%**
TOTAL	6.3648%
PRE-TAX EQUITY	6.7890%
PRE-TAX TOTAL	8.0296%

Note:

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

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

FPL - 2021 PROJECTED SEPARATION FACTORS

	SUMMARY
DEMAND	
E101 - Transmission	0.902300
E102 - Non-Stratified Production	0.956891
E103INT - Intermediate Strata Production	0.950081
E103PEAK - Peaking Strata Production	0.952778
E104 - Distribution	1.000000
ENERGY	
FPL201 - Total Sales	0.952084
FPL202 - Non-Stratified Sales	0.956788
FPL203INT - Intermediate Strata Sales	0.949979
FPL203PEAK - Peaking Strata Sales	0.952675
GENERAL PLANT	
I900 - LABOR	0.969888

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E101 - TRANSMISSION: 12CP Demand
December 2021 - PROJECTED (Dec 2019 LF)

RATE CLASS	12 CP - KW	VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW				% OF TOTAL	
	@ METER	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	351,746	0.0000	0.4203	0.5797	1.0222	1.0373	1.0623	0	153,357	216,599	369,956	1.6263%	1.8024%
CILC-1G	14,320	0.0000	0.0194	0.9806	1.0222	1.0373	1.0623	0	288	14,917	15,205	0.0668%	0.0741%
CILC-1T	180,360	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	184,369	0	0	184,369	0.8105%	0.8983%
GS(T)-1	1,217,559	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	1,293,382	1,293,382	5.6857%	6.3014%
GSCU-1	9,254	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	9,830	9,830	0.0432%	0.0479%
GSD(T)-1	4,422,592	0.0000	0.0032	0.9968	1.0222	1.0373	1.0623	0	14,571	4,683,084	4,697,655	20.6510%	22.8871%
GSLD(T)-1	1,673,190	0.0000	0.0355	0.9645	1.0222	1.0373	1.0623	0	61,649	1,714,253	1,775,902	7.8069%	8.6522%
GSLD(T)-2	365,038	0.0000	0.3971	0.6029	1.0222	1.0373	1.0623	0	150,372	233,775	384,147	1.6887%	1.8716%
GSLD(T)-3	35,401	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	36,188	0	0	36,188	0.1591%	0.1763%
MET	11,941	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	12,386	0	12,386	0.0544%	0.0603%
OL-1	68	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	72	72	0.0003%	0.0004%
OS-2	676	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	702	0	702	0.0031%	0.0034%
RS(T)-1	11,040,784	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	11,728,341	11,728,341	51.5581%	57.1408%
SL-1	352	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	374	374	0.0016%	0.0018%
SL-1M	55	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	59	59	0.0003%	0.0003%
SL-2	3,137	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	3,333	3,333	0.0147%	0.0162%
SL-2M	140	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	149	149	0.0007%	0.0007%
SST-DST	401	0.0000	0.6852	0.3148	1.0222	1.0373	1.0623	0	285	134	419	0.0018%	0.0020%
SST-TST	12,598	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	12,879	0	0	12,879	0.0566%	0.0627%
TOTAL RETAIL	19,339,613							233,435	393,609	19,898,301	20,525,345	90.2300%	100.0000%
FKEC	126,237	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	129,043	0	0	129,043	0.5673%	
FPUC (INT)	12,761	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	13,045	0	0	13,045	0.0573%	
FPUC (PEAK)	9,820	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	10,038	0	0	10,038	0.0441%	
HOMESTEAD	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	0.0147%	
HOMESTEAD (INT)	8,315	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	8,500	0	0	8,500	0.0374%	
LCEC	762,210	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	779,152	0	0	779,152	3.4252%	
MOORE HAVEN	571	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	583	0	0	583	0.0026%	
NEW SMYRNA BCH	7,337	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	7,500	0	0	7,500	0.0330%	
NEW SMYRNA BEACH (INT)	2,446	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	2,500	0	0	2,500	0.0110%	
NEW SMYRNA BCH (PEAK)	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	0.0147%	
QUINCY	3,098	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,167	0	0	3,167	0.0139%	
SEMINOLE (INT)	81,521	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	83,333	0	0	83,333	0.3663%	
WAUCHULA	1,875	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,917	0	0	1,917	0.0084%	
TRANS-SERV	1,151,427	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,177,020	0	0	1,177,020	5.1742%	
TOTAL WHOLESALE	2,174,139							2,222,464	0	0	2,222,464	9.7700%	
TOTAL FPL	21,513,752							2,455,899	393,609	19,898,301	22,747,809	100.0000%	
JURIS SEPARATION FACTOR												0.902300	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E102 - NON-STRATIFIED PRODUCTION: 12CP Demand
December 2021 - PROJECTED (Dec 2019 LF)

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	351,746	0	351,746	0.0000	0.4203	0.5797	1.0222	1.0373	1.0623	0	153,357	216,599	369,956	1.7247%	1.8024%
CILC-1G	14,320	0	14,320	0.0000	0.0194	0.9806	1.0222	1.0373	1.0623	0	288	14,917	15,205	0.0709%	0.0741%
CILC-1T	180,360	0	180,360	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	184,369	0	0	184,369	0.8595%	0.8983%
GS(T)-1	1,217,559	0	1,217,559	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	1,293,382	1,293,382	6.0297%	6.3014%
GSCU-1	9,254	0	9,254	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	9,830	9,830	0.0458%	0.0479%
GSD(T)-1	4,422,592	0	4,422,592	0.0000	0.0032	0.9968	1.0222	1.0373	1.0623	0	14,571	4,683,084	4,697,655	21.9004%	22.8871%
GSLD(T)-1	1,673,190	0	1,673,190	0.0000	0.0355	0.9645	1.0222	1.0373	1.0623	0	61,649	1,714,253	1,775,902	8.2792%	8.6522%
GSLD(T)-2	365,038	0	365,038	0.0000	0.3971	0.6029	1.0222	1.0373	1.0623	0	150,372	233,775	384,147	1.7909%	1.8716%
GSLD(T)-3	35,401	0	35,401	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	36,188	0	0	36,188	0.1687%	0.1763%
MET	11,941	0	11,941	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	12,386	0	12,386	0.0577%	0.0603%
OL-1	68	0	68	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	72	72	0.0003%	0.0004%
OS-2	676	0	676	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	702	0	702	0.0033%	0.0034%
RS(T)-1	11,040,784	0	11,040,784	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	11,728,341	11,728,341	54.6775%	57.1408%
SL-1	352	0	352	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	374	374	0.0017%	0.0018%
SL-1M	55	0	55	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	59	59	0.0003%	0.0003%
SL-2	3,137	0	3,137	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	3,333	3,333	0.0155%	0.0162%
SL-2M	140	0	140	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	149	149	0.0007%	0.0007%
SST-DST	401	0	401	0.0000	0.6852	0.3148	1.0222	1.0373	1.0623	0	285	134	419	0.0020%	0.0020%
SST-TST	12,598	0	12,598	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	12,879	0	0	12,879	0.0600%	0.0627%
TOTAL RETAIL	19,339,613	0	19,339,613							233,435	393,609	19,898,301	20,525,345	95.6891%	100.0000%
FKEC	126,237	0	126,237	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	129,043	0	0	129,043	0.6016%	
FPUC (INT)	12,761	(12,761)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
FPUC (PEAK)	9,820	(9,820)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
HOMESTEAD	3,261	0	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	0.0155%	
HOMESTEAD (INT)	8,315	(8,315)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
LCEC	762,210	0	762,210	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	779,152	0	0	779,152	3.6324%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	583	0	0	583	0.0027%	
NEW SMYRNA BCH	7,337	0	7,337	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	7,500	0	0	7,500	0.0350%	
NEW SMYRNA BCH (PEAK)	3,261	(3,261)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	2,446	(2,446)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
QUINCY	3,098	0	3,098	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,167	0	0	3,167	0.0148%	
SEMINOLE (INT)	81,521	(81,521)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
WAUCHULA	1,875	0	1,875	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,917	0	0	1,917	0.0089%	
TOTAL WHOLESALE	1,022,712	(118,124)	904,588							924,694	0	0	924,694	4.3109%	
TOTAL FPL	20,362,325	(118,124)	20,244,201							1,158,130	393,609	19,898,301	21,450,040	100.0000%	
JURIS SEPARATION FACTOR														0.956891	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103INT - INTERMEDIATE STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2021 - PROJECTED (Dec 2019 LF)

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	351,746	0	351,746	0.0000	0.4203	0.5797	1.0222	1.0373	1.0623	0	153,357	216,599	369,956	369,956	1.7125%	1.8024%
CILC-1G	14,320	0	14,320	0.0000	0.0194	0.9806	1.0222	1.0373	1.0623	0	288	14,917	15,205	15,205	0.0704%	0.0741%
CILC-1T	180,360	0	180,360	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	184,369	0	0	184,369	184,369	0.8534%	0.8983%
GS(T)-1	1,217,559	0	1,217,559	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	1,293,382	1,293,382	1,293,382	5.9868%	6.3014%
GSCU-1	9,254	0	9,254	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	9,830	9,830	9,830	0.0455%	0.0479%
GSD(T)-1	4,422,592	0	4,422,592	0.0000	0.0032	0.9968	1.0222	1.0373	1.0623	0	14,571	4,683,084	4,697,655	4,697,655	21.7446%	22.8871%
GSLD(T)-1	1,673,190	0	1,673,190	0.0000	0.0355	0.9645	1.0222	1.0373	1.0623	0	61,649	1,714,253	1,775,902	1,775,902	8.2203%	8.6522%
GSLD(T)-2	365,038	0	365,038	0.0000	0.3971	0.6029	1.0222	1.0373	1.0623	0	150,372	233,775	384,147	384,147	1.7781%	1.8716%
GSLD(T)-3	35,401	0	35,401	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	36,188	0	0	36,188	36,188	0.1675%	0.1763%
MET	11,941	0	11,941	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	12,386	0	12,386	12,386	0.0573%	0.0603%
OL-1	68	0	68	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	72	72	72	0.0003%	0.0004%
OS-2	676	0	676	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	702	0	702	702	0.0032%	0.0034%
RS(T)-1	11,040,784	0	11,040,784	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	11,728,341	11,728,341	11,728,341	54.2884%	57.1408%
SL-1	352	0	352	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	374	374	374	0.0017%	0.0018%
SL-1M	55	0	55	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	59	59	59	0.0003%	0.0003%
SL-2	3,137	0	3,137	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	3,333	3,333	3,333	0.0154%	0.0162%
SL-2M	140	0	140	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	149	149	149	0.0007%	0.0007%
SST-DST	401	0	401	0.0000	0.6852	0.3148	1.0222	1.0373	1.0623	0	285	134	419	419	0.0019%	0.0020%
SST-TST	12,598	0	12,598	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	12,879	0	0	12,879	12,879	0.0596%	0.0627%
TOTAL RETAIL	19,339,613	0	19,339,613							233,435	393,609	19,898,301	20,525,345	20,525,345	95.0081%	100.0000%
FKEC	126,237	0	126,237	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	129,043	0	0	129,043	129,043	0.5973%	
FPUC (INT)	12,761	0	12,761	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	13,045	0	0	13,045	**18,677**	0.0865%	
FPUC (PEAK)	9,820	(9,820)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
HOMESTEAD	3,261	0	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	3,333	0.0154%	
HOMESTEAD (INT)	8,315	0	8,315	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	8,500	0	0	8,500	**12,170**	0.0563%	
LCEC	762,210	0	762,210	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	779,152	0	0	779,152	779,152	3.6066%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	583	0	0	583	583	0.0027%	
NEW SMYRNA BCH	7,337	0	7,337	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	7,500	0	0	7,500	7,500	0.0347%	
NEW SMYRNA BCH (PEAK)	3,261	(3,261)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	2,446	0	2,446	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	2,500	0	0	2,500	**3,579**	0.0166%	
QUINCY	3,098	0	3,098	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,167	0	0	3,167	3,167	0.0147%	
SEMINOLE (INT)	81,521	0	81,521	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	83,333	0	0	83,333	**119,312**	0.5523%	
WAUCHULA	1,875	0	1,875	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,917	0	0	1,917	1,917	0.0089%	
TOTAL WHOLESALE	1,022,712	(13,081)	1,009,631							1,032,073	0	0	1,032,073	1,078,432	4.9919%	
TOTAL FPL	20,362,325	(13,081)	20,349,245							1,265,508	393,609	19,898,301	21,557,418	21,603,778	100.0000%	
JURIS SEPARATION FACTOR															**0.950081**	

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (INT) Amount	HOMESTEAD (INT) Amount	NSB (INT) Amount	SEMINOLE (INT) Amount
1) Contract Wholesale Customer 12 CP	1	Load Forecast * Loss Factor	13,045	8,500	2,500	83,333
2) Intermediate System Capacity Net of Reserve Margin	2					
Intermediate Summer Capacity	3	2020-2029 TYSP	18,107,000	18,107,000	18,107,000	18,107,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%	120.0%	120.0%
Intermediate System Capacity Net of Reserve Margin	5	L3 / L4	15,089,167	15,089,167	15,089,167	15,089,167
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.000865	0.000563	0.000166	0.005523
3) Contract Adjusted 12CP @ Generation	7					
Total System 12CP Excluding All Stratified Contracts	8		21,450,040	21,450,040	21,450,040	21,450,040
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99288	0.99288	0.99288	0.99288
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	21,603,778	21,603,778	21,603,778	21,603,778
Contract Adjusted 12CP @ Generation	11	L6 * L11	18,677	12,170	3,579	119,312

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E103PK - PEAKING STRATA PRODUCTION (CONTRACT ADJUSTED): 12CP Demand
December 2021 - PROJECTED (Dec 2019 LF)

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	351,746	0	351,746	0.0000	0.4203	0.5797	1.0222	1.0373	1.0623	0	153,357	216,599	369,956	369,956	1.7173%	1.8024%
CILC-1G	14,320	0	14,320	0.0000	0.0194	0.9806	1.0222	1.0373	1.0623	0	288	14,917	15,205	15,205	0.0706%	0.0741%
CILC-1T	180,360	0	180,360	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	184,369	0	0	184,369	184,369	0.8558%	0.8983%
GS(T)-1	1,217,559	0	1,217,559	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	1,293,382	1,293,382	1,293,382	6.0038%	6.3014%
GSCU-1	9,254	0	9,254	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	9,830	9,830	9,830	0.0456%	0.0479%
GSD(T)-1	4,422,592	0	4,422,592	0.0000	0.0032	0.9968	1.0222	1.0373	1.0623	0	14,571	4,683,084	4,697,655	4,697,655	21.8063%	22.8871%
GSLD(T)-1	1,673,190	0	1,673,190	0.0000	0.0355	0.9645	1.0222	1.0373	1.0623	0	61,649	1,714,253	1,775,902	1,775,902	8.2437%	8.6522%
GSLD(T)-2	365,038	0	365,038	0.0000	0.3971	0.6029	1.0222	1.0373	1.0623	0	150,372	233,775	384,147	384,147	1.7832%	1.8716%
GSLD(T)-3	35,401	0	35,401	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	36,188	0	0	36,188	36,188	0.1680%	0.1763%
MET	11,941	0	11,941	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	12,386	0	12,386	12,386	0.0575%	0.0603%
OL-1	68	0	68	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	72	72	72	0.0003%	0.0004%
OS-2	676	0	676	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	702	0	702	702	0.0033%	0.0034%
RS(T)-1	11,040,784	0	11,040,784	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	11,728,341	11,728,341	11,728,341	54.4425%	57.1408%
SL-1	352	0	352	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	374	374	374	0.0017%	0.0018%
SL-1M	55	0	55	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	59	59	59	0.0003%	0.0003%
SL-2	3,137	0	3,137	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	3,333	3,333	3,333	0.0155%	0.0162%
SL-2M	140	0	140	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	149	149	149	0.0007%	0.0007%
SST-DST	401	0	401	0.0000	0.6852	0.3148	1.0222	1.0373	1.0623	0	285	134	419	419	0.0019%	0.0020%
SST-TST	12,598	0	12,598	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	12,879	0	0	12,879	12,879	0.0598%	0.0627%
TOTAL RETAIL	19,339,613	0	19,339,613							233,435	393,609	19,898,301	20,525,345	20,525,345	95.2778%	100.0000%
FKEC	126,237	0	126,237	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	129,043	0	0	129,043	129,043	0.5990%	
FPUC (INT)	12,761	(12,761)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
FPUC (PEAK)	9,820	0	9,820	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	10,038	0	0	10,038	**69,515**	0.3227%	
HOMESTEAD	3,261	0	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	3,333	0.0155%	
HOMESTEAD (INT)	8,315	(8,315)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
LCEC	762,210	0	762,210	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	779,152	0	0	779,152	779,152	3.6168%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	583	0	0	583	583	0.0027%	
NEW SMYRNA BCH	7,337	0	7,337	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	7,500	0	0	7,500	7,500	0.0348%	
NEW SMYRNA BCH (PEAK)	3,261	0	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	**23,083**	0.1072%	
NEW SMYRNA BEACH (INT)	2,446	(2,446)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
QUINCY	3,098	0	3,098	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,167	0	0	3,167	3,167	0.0147%	
SEMINOLE (INT)	81,521	(81,521)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
WAUCHULA	1,875	0	1,875	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,917	0	0	1,917	1,917	0.0089%	
TOTAL WHOLESALE	1,022,712	(105,044)	917,669							938,066	0	0	938,066	1,017,293	4.7222%	
TOTAL FPL	20,362,325	(105,044)	20,257,282							1,171,501	393,609	19,898,301	21,463,411	21,542,638	100.0000%	
JURIS SEPARATION FACTOR															**0.952778**	

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (PEAK) Amount	NSB (PEAK) Amount
1) Contract Wholesale Customer 12 CP	1	Load Forecast * Loss Factor	10,038	3,333
2) Peaking System Capacity Net of Reserve Margin	2			
Peaking Summer Capacity	3	2020-2029 TYSP	3,733,000	3,733,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%
Peaking System Capacity Net of Reserve Margin	5	L3 / L4	3,110,833	3,110,833
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.00323	0.00107
3) Contract Adjusted 12CP @ Generation	7			
Total System 12CP Excluding All Stratified Contracts	8		21,450,040	21,450,040
Contribution (Excluding Peaking Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99570	0.99570
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	21,542,638	21,542,638
Contract Adjusted 12CP @ Generation	11	L6 * L11	69,515	23,083

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E104 - DISTRIBUTION: Group Non-Coincident Peak (GNCP) Demand
December 2021 - PROJECTED (Dec 2019 LF)

RATE CLASS	MAX GNCP			VOLTAGE LEVEL % - DEMAND		LOSS EXPANSION FACTORS		MAX GNCP @ GENERATION			% OF TOTAL	
	@ METER	ADJ	ADJUSTED	PRIMARY	SECOND	PRIMARY	SECOND	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	381,582	0	381,582	0.4203	0.5797	1.0373	1.0623	166,365	234,971	401,336	1.5990%	1.5990%
CILC-1G	16,072	0	16,072	0.0194	0.9806	1.0373	1.0623	323	16,742	17,065	0.0680%	0.0680%
CILC-1T	210,921	(210,921)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	0.0000%
GS(T)-1	1,432,038	0	1,432,038	0.0000	1.0000	1.0373	1.0623	0	1,521,218	1,521,218	6.0606%	6.0606%
GSCU-1	10,078	0	10,078	0.0000	1.0000	1.0373	1.0623	0	10,706	10,706	0.0427%	0.0427%
GSD(T)-1	4,999,674	0	4,999,674	0.0032	0.9968	1.0373	1.0623	16,473	5,294,156	5,310,629	21.1579%	21.1579%
GSLD(T)-1	1,986,886	0	1,986,886	0.0355	0.9645	1.0373	1.0623	73,207	2,035,647	2,108,854	8.4018%	8.4018%
GSLD(T)-2	423,490	0	423,490	0.3971	0.6029	1.0373	1.0623	174,450	271,209	445,659	1.7755%	1.7755%
GSLD(T)-3	42,860	(42,860)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	0.0000%
MET	14,644	0	14,644	1.0000	0.0000	1.0373	1.0623	15,189	0	15,189	0.0605%	0.0605%
OL-1	25,140	0	25,140	0.0000	1.0000	1.0373	1.0623	0	26,706	26,706	0.1064%	0.1064%
OS-2	8,295	0	8,295	1.0000	0.0000	1.0373	1.0623	8,604	0	8,604	0.0343%	0.0343%
RS(T)-1	14,201,390	0	14,201,390	0.0000	1.0000	1.0373	1.0623	0	15,085,772	15,085,772	60.1027%	60.1027%
SL-1	127,448	0	127,448	0.0000	1.0000	1.0373	1.0623	0	135,385	135,385	0.5394%	0.5394%
SL-1M	2,340	0	2,340	0.0000	1.0000	1.0373	1.0623	0	2,486	2,486	0.0099%	0.0099%
SL-2	3,376	0	3,376	0.0000	1.0000	1.0373	1.0623	0	3,586	3,586	0.0143%	0.0143%
SL-2M	268	0	268	0.0000	1.0000	1.0373	1.0623	0	284	284	0.0011%	0.0011%
SST-DST	6,217	0	6,217	0.6852	0.3148	1.0373	1.0623	4,419	2,079	6,498	0.0259%	0.0259%
SST-TST	71,558	(71,558)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	0.0000%
TOTAL RETAIL	23,964,276	(325,339)	23,638,937					459,030	24,640,946	25,099,976	100.0000%	100.0000%
FKEC	154,278	(154,278)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
FPUC (INT)	14,001	(14,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
FPUC (PEAK)	33,469	(33,469)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
HOMESTEAD	25,001	(25,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
HOMESTEAD (INT)	51,001	(51,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
LCEC	1,012,512	(1,012,512)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
MOORE HAVEN	4,001	(4,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
NEW SMYRNA BCH	45,001	(45,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	20,001	(20,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
NEW SMYRNA BCH (PEAK)	20,001	(20,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
QUINCY	19,001	(19,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
SEMINOLE (INT)	200,001	(200,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
WAUCHULA	14,001	(14,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
TOTAL WHOLESALE	1,612,269	(1,612,269)	0					0	0	0	0.0000%	
TOTAL FPL	25,576,545	(1,937,608)	23,638,937					459,030	24,640,946	25,099,976	100.0000%	
JURIS SEPARATION FACTOR											1.000000	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E201 - TOTAL SALES: Total Annual Energy
December 2021 - PROJECTED (Dec 2019 LF)

RATE CLASS	MWH SALES	VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,635,788	0.0000	0.4148	0.5852	1.0169	1.0282	1.0468	0	1,124,208	1,614,572	2,738,780	2.2298%	2.3420%
CILC-1G	104,193	0.0000	0.0182	0.9818	1.0169	1.0282	1.0468	0	1,951	107,085	109,036	0.0888%	0.0932%
CILC-1T	1,470,591	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	1,495,380	0	0	1,495,380	1.2175%	1.2787%
GS(T)-1	6,506,169	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	6,810,760	6,810,760	5.5450%	5.8240%
GSCU-1	77,567	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	81,199	81,199	0.0661%	0.0694%
GSD(T)-1	27,339,373	0.0000	0.0032	0.9968	1.0169	1.0282	1.0468	0	91,279	28,526,352	28,617,631	23.2989%	24.4715%
GSLD(T)-1	10,202,111	0.0000	0.0343	0.9657	1.0169	1.0282	1.0468	0	359,942	10,313,256	10,673,197	8.6895%	9.1269%
GSLD(T)-2	2,700,592	0.0000	0.3964	0.6036	1.0169	1.0282	1.0468	0	1,100,605	1,706,441	2,807,046	2.2853%	2.4004%
GSLD(T)-3	259,243	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	263,612	0	0	263,612	0.2146%	0.2254%
MET	80,326	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	82,587	0	82,587	0.0672%	0.0706%
OL-1	92,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	96,759	96,759	0.0788%	0.0827%
OS-2	9,166	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	9,424	0	9,424	0.0077%	0.0081%
RS(T)-1	59,729,074	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	62,525,339	62,525,339	50.9048%	53.4667%
SL-1	474,786	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	497,013	497,013	0.4046%	0.4250%
SL-1M	8,734	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	9,143	9,143	0.0074%	0.0078%
SL-2	26,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	27,669	27,669	0.0225%	0.0237%
SL-2M	1,665	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	1,743	1,743	0.0014%	0.0015%
SST-DST	1,850	0.0000	0.5444	0.4556	1.0169	1.0282	1.0468	0	1,035	882	1,918	0.0016%	0.0016%
SST-TST	92,788	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94,352	0	0	94,352	0.0768%	0.0807%
TOTAL RETAIL	111,812,880							1,853,345	2,771,031	112,318,213	116,942,590	95.2084%	100.0000%
FKEC	805,763	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	819,345	0	0	819,345	0.6671%	
FPUC (INT)	101,728	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	103,443	0	0	103,443	0.0842%	
FPUC (PEAK)	53,455	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	54,356	0	0	54,356	0.0443%	
HOMESTEAD	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	0.0001%	
HOMESTEAD (INT)	408	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	415	0	0	415	0.0003%	
LCEC	4,387,467	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	4,461,425	0	0	4,461,425	3.6323%	
MOORE HAVEN	28	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	28	0	0	28	0.0000%	
NEW SMYRNA BCH	360	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	366	0	0	366	0.0003%	
NEW SMYRNA BEACH (INT)	12,120	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	12,324	0	0	12,324	0.0100%	
NEW SMYRNA BCH (PEAK)	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	0.0001%	
QUINCY	152	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	155	0	0	155	0.0001%	
SEMINOLE (INT)	425,973	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	433,153	0	0	433,153	0.3527%	
WAUCHULA	92	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94	0	0	94	0.0001%	
TOTAL WHOLESALE	5,787,865							5,885,429	0	0	5,885,429	4.7916%	
TOTAL FPL	117,600,745							7,738,774	2,771,031	112,318,213	122,828,019	100.0000%	
JURIS SEPARATION FACTOR												0.952084	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E202 - NON-STRATIFIED SALES: Total Annual Energy
December 2021 - PROJECTED (Dec 2019 LF)

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,635,788	0	2,635,788	0.0000	0.4148	0.5852	1.0169	1.0282	1.0468	0	1,124,208	1,614,572	2,738,780	2.2408%	2.3420%
CILC-1G	104,193	0	104,193	0.0000	0.0182	0.9818	1.0169	1.0282	1.0468	0	1,951	107,085	109,036	0.0892%	0.0932%
CILC-1T	1,470,591	0	1,470,591	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	1,495,380	0	0	1,495,380	1.2235%	1.2787%
GS(T)-1	6,506,169	0	6,506,169	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	6,810,760	6,810,760	5.5724%	5.8240%
GSCU-1	77,567	0	77,567	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	81,199	81,199	0.0664%	0.0694%
GSD(T)-1	27,339,373	0	27,339,373	0.0000	0.0032	0.9968	1.0169	1.0282	1.0468	0	91,279	28,526,352	28,617,631	23.4141%	24.4715%
GSLD(T)-1	10,202,111	0	10,202,111	0.0000	0.0343	0.9657	1.0169	1.0282	1.0468	0	359,942	10,313,256	10,673,197	8.7325%	9.1269%
GSLD(T)-2	2,700,592	0	2,700,592	0.0000	0.3964	0.6036	1.0169	1.0282	1.0468	0	1,100,605	1,706,441	2,807,046	2.2966%	2.4004%
GSLD(T)-3	259,243	0	259,243	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	263,612	0	0	263,612	0.2157%	0.2254%
MET	80,326	0	80,326	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	82,587	0	82,587	0.0676%	0.0706%
OL-1	92,432	0	92,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	96,759	96,759	0.0792%	0.0827%
OS-2	9,166	0	9,166	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	9,424	0	9,424	0.0077%	0.0081%
RS(T)-1	59,729,074	0	59,729,074	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	62,525,339	62,525,339	51.1563%	53.4667%
SL-1	474,786	0	474,786	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	497,013	497,013	0.4066%	0.4250%
SL-1M	8,734	0	8,734	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	9,143	9,143	0.0075%	0.0078%
SL-2	26,432	0	26,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	27,669	27,669	0.0226%	0.0237%
SL-2M	1,665	0	1,665	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	1,743	1,743	0.0014%	0.0015%
SST-DST	1,850	0	1,850	0.0000	0.5444	0.4556	1.0169	1.0282	1.0468	0	1,035	882	1,918	0.0016%	0.0016%
SST-TST	92,788	0	92,788	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94,352	0	0	94,352	0.0772%	0.0807%
TOTAL RETAIL	111,812,880	0	111,812,880							1,853,345	2,771,031	112,318,213	116,942,590	95.6788%	100.0000%
FKEC	805,763	0	805,763	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	819,345	0	0	819,345	0.6704%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
HOMESTEAD	160	0	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	0.0001%	
HOMESTEAD (INT)	408	(408)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
LCEC	4,387,467	0	4,387,467	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	4,461,425	0	0	4,461,425	3.6502%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	28	0	0	28	0.0000%	
NEW SMYRNA BCH	360	0	360	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	366	0	0	366	0.0003%	
NEW SMYRNA BCH (PEAK)	160	(160)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	12,120	(12,120)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	155	0	0	155	0.0001%	
SEMINOLE (INT)	425,973	(425,973)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94	0	0	94	0.0001%	
TOTAL WHOLESALE	5,787,865	(593,844)	5,194,021							5,281,575	0	0	5,281,575	4.3212%	
TOTAL FPL	117,600,745	(593,844)	117,006,901							7,134,920	2,771,031	112,318,213	122,224,164	100.0000%	
JURIS SEPARATION FACTOR														**0.956788**	

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E203INT - INTERMEDIATE STRATA SALES (CONTRACT ADJUSTED): Total Annual Energy
December 2021 - PROJECTED (Dec 2019 LF)

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	2,635,788	0	2,635,788	0.0000	0.4148	0.5852	1.0169	1.0282	1.0468	0	1,124,208	1,614,572	2,738,780	2,738,780	2.2248%	2.3420%
CILC-1G	104,193	0	104,193	0.0000	0.0182	0.9818	1.0169	1.0282	1.0468	0	1,951	107,085	109,036	109,036	0.0886%	0.0932%
CILC-1T	1,470,591	0	1,470,591	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	1,495,380	0	0	1,495,380	1,495,380	1.2148%	1.2787%
GS(T)-1	6,506,169	0	6,506,169	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	6,810,760	6,810,760	6,810,760	5.5327%	5.8240%
GSCU-1	77,567	0	77,567	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	81,199	81,199	81,199	0.0660%	0.0694%
GSD(T)-1	27,339,373	0	27,339,373	0.0000	0.0032	0.9968	1.0169	1.0282	1.0468	0	91,279	28,526,352	28,617,631	28,617,631	23.2474%	24.4715%
GSLD(T)-1	10,202,111	0	10,202,111	0.0000	0.0343	0.9657	1.0169	1.0282	1.0468	0	359,942	10,313,256	10,673,197	10,673,197	8.6703%	9.1269%
GSLD(T)-2	2,700,592	0	2,700,592	0.0000	0.3964	0.6036	1.0169	1.0282	1.0468	0	1,100,605	1,706,441	2,807,046	2,807,046	2.2803%	2.4004%
GSLD(T)-3	259,243	0	259,243	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	263,612	0	0	263,612	263,612	0.2141%	0.2254%
MET	80,326	0	80,326	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	82,587	0	82,587	82,587	0.0671%	0.0706%
OL-1	92,432	0	92,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	96,759	96,759	96,759	0.0786%	0.0827%
OS-2	9,166	0	9,166	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	9,424	0	9,424	9,424	0.0077%	0.0081%
RS(T)-1	59,729,074	0	59,729,074	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	62,525,339	62,525,339	62,525,339	50.7922%	53.4667%
SL-1	474,786	0	474,786	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	497,013	497,013	497,013	0.4037%	0.4250%
SL-1M	8,734	0	8,734	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	9,143	9,143	9,143	0.0074%	0.0078%
SL-2	26,432	0	26,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	27,669	27,669	27,669	0.0225%	0.0237%
SL-2M	1,665	0	1,665	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	1,743	1,743	1,743	0.0014%	0.0015%
SST-DST	1,850	0	1,850	0.0000	0.5444	0.4556	1.0169	1.0282	1.0468	0	1,035	882	1,918	1,918	0.0016%	0.0016%
SST-TST	92,788	0	92,788	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94,352	0	0	94,352	94,352	0.0766%	0.0807%
TOTAL RETAIL	111,812,880	0	111,812,880							1,853,345	2,771,031	112,318,213	116,942,590	116,942,590	94.9979%	100.0000%
FKEC	805,763	0	805,763	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	819,345	0	0	819,345	819,345	0.6656%	
FPUC (INT)	101,728	0	101,728	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	103,443	0	0	103,443	**106,424**	0.0865%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
HOMESTEAD	160	0	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	163	0.0001%	
HOMESTEAD (INT)	408	0	408	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	415	0	0	415	**69,345**	0.0563%	
LCEC	4,387,467	0	4,387,467	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	4,461,425	0	0	4,461,425	4,461,425	3.6242%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	28	0	0	28	28	0.0000%	
NEW SMYRNA BCH	360	0	360	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	366	0	0	366	366	0.0003%	
NEW SMYRNA BCH (PEAK)	160	(160)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	12,120	0	12,120	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	12,324	0	0	12,324	**20,395**	0.0166%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	155	0	0	155	155	0.0001%	
SEMINOLE (INT)	425,973	0	425,973	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	433,153	0	0	433,153	**679,849**	0.5523%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94	0	0	94	94	0.0001%	
TOTAL WHOLESALE	5,787,865	(53,615)	5,734,251							5,830,911	0	0	5,830,911	6,157,587	5.0021%	
TOTAL FPL	117,600,745	(53,615)	117,547,131							7,684,256	2,771,031	112,318,213	122,773,500	123,100,177	100.0000%	
JURIS SEPARATION FACTOR															**0.949979**	

Contract Adjusted MWH Sales @ Generation -	Line No.	Source/Formula	FPUC (INT) Amount	HOMESTEAD (INT) Amount	NSB (INT) Amount	SEMINOLE (INT) Amount
1) Contract Wholesale Customer 12 CP	1	Load Forecast * Loss Factor	13,045	8,500	2,500	83,333
2) Intermediate System Capacity Net of Reserve Margin	2					
Intermediate Summer Capacity	3	2020-2029 TYSP	18,107,000	18,107,000	18,107,000	18,107,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%	120.0%	120.0%
Intermediate System Capacity Net of Reserve Margin	5	L3 / L4	15,089,167	15,089,167	15,089,167	15,089,167
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.000865	0.000563	0.000166	0.005523
3) Contract Adjusted MWH Sales @ Generation	7					
Total System MWH Sales Excluding All Stratified Contracts	8		122,224,164	122,224,164	122,224,164	122,224,164
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99288	0.99288	0.99288	0.99288
Total System MWH Sales Including Intermediate Stratified Contracts	10	L8 / L9	123,100,177	123,100,177	123,100,177	123,100,177
Contract Adjusted MWH Sales @ Generation	11	L6 * L11	106,424	69,345	20,395	679,849

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
E203PK - PEAKING STRATA SALES (CONTRACT ADJUSTED): Total Annual Energy
December 2021 - PROJECTED (Dec 2019 LF)

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	2,635,788	0	2,635,788	0.0000	0.4148	0.5852	1.0169	1.0282	1.0468	0	1,124,208	1,614,572	2,738,780	2,738,780	2.2312%	2.3420%
CILC-1G	104,193	0	104,193	0.0000	0.0182	0.9818	1.0169	1.0282	1.0468	0	1,951	107,085	109,036	109,036	0.0888%	0.0932%
CILC-1T	1,470,591	0	1,470,591	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	1,495,380	0	0	1,495,380	1,495,380	1.2182%	1.2787%
GS(T)-1	6,506,169	0	6,506,169	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	6,810,760	6,810,760	6,810,760	5.5484%	5.8240%
GSCU-1	77,567	0	77,567	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	81,199	81,199	81,199	0.0661%	0.0694%
GSD(T)-1	27,339,373	0	27,339,373	0.0000	0.0032	0.9968	1.0169	1.0282	1.0468	0	91,279	28,526,352	28,617,631	28,617,631	23.3134%	24.4715%
GSLD(T)-1	10,202,111	0	10,202,111	0.0000	0.0343	0.9657	1.0169	1.0282	1.0468	0	359,942	10,313,256	10,673,197	10,673,197	8.6949%	9.1269%
GSLD(T)-2	2,700,592	0	2,700,592	0.0000	0.3964	0.6036	1.0169	1.0282	1.0468	0	1,100,605	1,706,441	2,807,046	2,807,046	2.2868%	2.4004%
GSLD(T)-3	259,243	0	259,243	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	263,612	0	0	263,612	263,612	0.2148%	0.2254%
MET	80,326	0	80,326	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	82,587	0	82,587	82,587	0.0673%	0.0706%
OL-1	92,432	0	92,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	96,759	96,759	96,759	0.0788%	0.0827%
OS-2	9,166	0	9,166	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	9,424	0	9,424	9,424	0.0077%	0.0081%
RS(T)-1	59,729,074	0	59,729,074	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	62,525,339	62,525,339	62,525,339	50.9364%	53.4667%
SL-1	474,786	0	474,786	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	497,013	497,013	497,013	0.4049%	0.4250%
SL-1M	8,734	0	8,734	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	9,143	9,143	9,143	0.0074%	0.0078%
SL-2	26,432	0	26,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	27,669	27,669	27,669	0.0225%	0.0237%
SL-2M	1,665	0	1,665	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	1,743	1,743	1,743	0.0014%	0.0015%
SST-DST	1,850	0	1,850	0.0000	0.5444	0.4556	1.0169	1.0282	1.0468	0	1,035	882	1,918	1,918	0.0016%	0.0016%
SST-TST	92,788	0	92,788	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94,352	0	0	94,352	94,352	0.0769%	0.0807%
TOTAL RETAIL	111,812,880	0	111,812,880							1,853,345	2,771,031	112,318,213	116,942,590	116,942,590	95.2675%	100.0000%
FKEC	805,763	0	805,763	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	819,345	0	0	819,345	819,345	0.6675%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	0	53,455	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	54,356	0	0	54,356	**396,101**	0.3227%	
HOMESTEAD	160	0	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	163	0.0001%	
HOMESTEAD (INT)	408	(408)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
LCEC	4,387,467	0	4,387,467	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	4,461,425	0	0	4,461,425	4,461,425	3.6345%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	28	0	0	28	28	0.0000%	
NEW SMYRNA BCH	360	0	360	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	366	0	0	366	366	0.0003%	
NEW SMYRNA BCH (PEAK)	160	0	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	**131,532**	0.1072%	
NEW SMYRNA BEACH (INT)	12,120	(12,120)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	155	0	0	155	155	0.0001%	
SEMINOLE (INT)	425,973	(425,973)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94	0	0	94	94	0.0001%	
TOTAL WHOLESALE	5,787,865	(540,229)	5,247,636							5,336,093	0	0	5,336,093	5,809,207	4.7325%	
TOTAL FPL	117,600,745	(540,229)	117,060,516							7,189,438	2,771,031	112,318,213	122,278,683	122,751,797	100.0000%	
JURIS SEPARATION FACTOR															**0.952675**	

Contract Adjusted MWH Sales @ Generation -	Line No.	Source/Formula	FPUC (PEAK) Amount	NSB (PEAK) Amount
1) Contract Wholesale Customer 12 CP	1	Load Forecast * Loss Factor	10,038	3,333
2) Peaker System Capacity Net of Reserve Margin	2			
Peaker Summer Capacity	3	2020-2029 TYSP	3,733,000	3,733,000
Divide By: System Capacity Including Reserve Margin	4		120.0%	120.0%
Peaker System Capacity Net of Reserve Margin	5	L3 / L4	3,110,833	3,110,833
Contract Rate Class Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.003227	0.001072
3) Contract Adjusted MWH Sales @ Generation	7			
Total System MWH Sales @ Generation Excluding Peaker Stratified Contracts	8		122,224,164	122,224,164
Contribution (Excluding Peaker Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99570	0.99570
Total System MWH Sales @ Generation Including Peaker Stratified Contracts	10	L8 / L9	122,751,797	122,751,797
Contract Adjusted 12CP @ Generation	11	L6 * L10	396,101	131,532

FLORIDA POWER & LIGHT
JURISDICTIONAL SEPARATION STUDY AND RETAIL COST OF SERVICE STUDY
SEP - Internals Based on Externals (B2S)
December 2021 - PROJECTED (Dec 2019 LF)

SEP - INTERNAL FACTORS BASED ON EXTERNAL FACTORS	ALLOCATOR(S)	COMPANY PER BOOKS	SEPARATION FACTOR	JURISDICTIONAL	INTERNAL SEPARATION FACTOR
I900-LABOR-EXC-A&G					
L_INC100000 - STEAM O&M PAY - OPERAT SUPERV & ENG	BLENDED	1,147,178.18	0.955397	1,096,010.93	
L_INC101210 - STEAM O&M PAY - FUEL - NON RECOVERABLE OIL	BLENDED	167,219.99	0.952802	159,327.48	
L_INC102000 - STEAM O&M PAY - STEAM EXPENSES	BLENDED	598,893.50	0.956249	572,691.59	
L_INC105000 - STEAM O&M PAY - ELECTRIC EXPENSES	BLENDED	478,249.34	0.954503	456,490.19	
L_INC106000 - STEAM O&M PAY - MISC STEAM POWER EXPENSES	BLENDED	5,761,012.02	0.953711	5,494,339.08	
L_INC110000 - STEAM O&M PAY - MAINT SUPERV & ENG	BLENDED	605,092.15	0.955914	578,415.90	
L_INC111000 - STEAM O&M PAY - MAINT OF STRUCTURES	BLENDED	1,319,446.70	0.953439	1,258,011.63	
L_INC112000 - STEAM O&M PAY - MAINT OF BOILER PLANT	BLENDED	1,922,239.13	0.955373	1,836,455.69	
L_INC113000 - STEAM O&M PAY - MAINT OF ELECTRIC PLANT	BLENDED	989,722.79	0.952962	943,168.49	
L_INC114000 - STEAM O&M PAY - MAINT OF MISC STEAM PLT	BLENDED	525,536.28	0.953780	501,246.12	
L_INC117000 - NUCLEAR O&M PAY - OPER SUPERV & ENG	E102NS	39,165,056.11	0.957097	37,484,775.04	
L_INC119000 - NUCLEAR O&M PAY - COOLANTS AND WATER	E102NS	4,386,699.37	0.956891	4,197,592.18	
L_INC120000 - NUCLEAR O&M PAY - STEAM EXPENSES	E102NS	44,137,818.52	0.956891	42,235,071.66	
L_INC123000 - NUCLEAR O&M PAY - ELECTRIC EXP	E102NS	376.85	0.956891	360.60	
L_INC124000 - NUCLEAR O&M PAY - MISC NUCLEAR POWER EXP	E102NS	34,409,745.69	0.956891	32,926,368.44	
L_INC128000 - NUCLEAR O&M PAY - MAINT SUPERVISION & ENGINEERING	E202NS	39,200,661.09	0.956788	37,506,714.34	
L_INC129000 - NUCLEAR O&M PAY - MAINT OF STRUCTURES	E102NS	48,658.53	0.956891	46,560.90	
L_INC130000 - NUCLEAR O&M PAY - MAINT OF REACTOR PLANT	E201	132,730.24	0.956788	126,994.68	
L_INC131000 - NUCLEAR O&M PAY - MAINT OF ELECTRIC PLANT	E201	740,043.79	0.956877	708,131.00	
L_INC132000 - NUCLEAR O&M PAY - MAINT OF MISC NUCLEAR PLANT	E201	5,759.69	0.956788	5,510.80	
L_INC146000 - OTH PWR O&M PAY - OPERAT SUPERV & ENG	BLENDED	12,409,546.18	0.951193	11,803,876.11	
L_INC147200 - OTH PWR O&M PAY - FUEL N- RECOV EMISSIONS FEE	E203INT	3,151,294.58	0.952021	3,000,097.40	
L_INC148000 - OTH PWR O&M PAY- GENERATION EXPENSES	BLENDED	8,873,470.21	0.950224	8,431,788.00	
L_INC149000 - OTH PWR O&M PAY - MISC OTHER POWER GENERATION EXPENSES	BLENDED	16,351,473.57	0.950649	15,544,510.77	
L_INC151000 - OTH PWR O&M PAY - MAINT SUPERV & ENG	BLENDED	5,687,089.80	0.950794	5,407,253.26	
L_INC152000 - OTH PWR O&M PAY - MAINT OF STRUCTURES	BLENDED	5,975,427.19	0.950201	5,677,856.48	
L_INC153000 - OTH PWR O&M PAY - MAINT GENERATING & ELECTRIC PLANT	BLENDED	20,934,011.09	0.950258	19,892,712.79	
L_INC154000 - OTH PWR O&M PAY - MAINT MISC OTHER PWR GENERAT	BLENDED	3,782,572.64	0.950257	3,594,416.03	
L_INC156000 - OTH PWR O&M PAY - SYSTEM CONTROL & LOAD DISPATCH	E103INT	808,421.13	0.950081	768,065.80	
L_INC157000 - OTH PWR O&M PAY - OTHER EXPENSES LOC 955	E103INT	1,811,998.86	0.950081	1,721,546.24	
L_INC260010 - TRANS O&M PAY - OPERATION SUPERV & ENGINEERING	E101	4,731,091.68	0.902300	4,268,863.39	
L_INC261000 - TRANS O&M PAY - LOAD DISPATCHING	E101	2,919,935.27	0.902300	2,634,657.20	
L_INC262000 - TRANS O&M PAY - STATION EXPENSES	E101	268,504.32	0.902300	242,271.41	
L_INC263000 - TRANS O&M PAY - OVERHEAD LINE EXPENSES	E101	64,220.91	0.902300	57,946.51	
L_INC266000 - TRANS O&M PAY - MISC TRANSMISSION EXPENSES	E101	2,919,880.82	0.902300	2,634,608.08	
L_INC267000 - TRANS O&M - RENTS	E101				
L_INC268010 - TRANS O&M PAY - MAINT SUPERV & ENG	E101	903,249.89	0.902300	815,002.26	
L_INC269000 - TRANS O&M PAY - MAINT OF STRUCTURES	E101	2,345,258.74	0.902300	2,116,126.65	
L_INC270000 - TRANS O&M PAY - MAINT OF STATION EQ	E101	1,629,500.36	0.902300	1,470,297.96	
L_INC271000 - TRANS O&M PAY - MAINT OF OVERHEAD LINES	E101	1,387,714.48	0.902300	1,252,134.59	
L_INC272000 - TRANS O&M PAY - MAINT UNDERGROUND LINES	E101	18,562.68	0.902300	16,749.10	
L_INC273000 - TRANS O&M PAY - MAINT OF MISC TRANS PLANT	E101				
L_INC380000 - DIST O&M PAY - OPERATION SUPERVISION AND ENGINEERING	E104	11,618,950.51	1.000000	11,618,950.51	
L_INC381000 - DIST O&M PAY - LOAD DISPATCHING	E104				
L_INC382000 - DIST O&M PAY - SUBSTATION EXPENSES	E104	616,954.80	1.000000	616,954.80	
L_INC383000 - DIST O&M PAY - OVERHEAD LINE EXPENSES	I365T	3,608,330.73	1.000000	3,608,330.73	
L_INC384000 - DIST O&M PAY - UNDERGROUND LINE EXP	I367T	1,332,549.90	1.000000	1,332,549.90	
L_INC385000 - DIST O&M PAY - STREET LIGHTING AND SIGNAL SYSTEM EXPENSES	E508	185,707.33	1.000000	185,707.33	
L_INC386000 - DIST O&M PAY - METER EXPENSES	E325	9,015,012.38	0.996099	8,979,847.56	
L_INC387000 - DIST O&M PAY - CUSTOMER INSTALLATIONS EXP	E309	728,886.16	1.000000	728,886.16	
L_INC388000 - DIST O&M PAY - MISC DISTRIBUTION EXPENSES	E104	28,506,232.92	1.000000	28,506,232.92	
L_INC389000 - DIST O&M - RENTS	E104				
L_INC390000 - DIST O&M PAY - MAINT SUPERV & ENG	E104	15,849,141.15	1.000000	15,849,141.15	
L_INC391000 - DIST O&M PAY - MAINT OF STRUCTURES	E104	29,858.01	1.000000	29,858.01	
L_INC392000 - DIST O&M PAY - MAINT OF STATION EQ	E104	2,689,213.41	1.000000	2,689,213.41	
L_INC393000 - DIST O&M PAY - MAINT OF OVERHEAD LINES	I365T	25,504,837.31	1.000000	25,504,837.31	
L_INC394000 - DIST O&M PAY - MAINT UNDERGROUND LINES	I367T	11,391,291.41	1.000000	11,391,291.41	
L_INC395000 - DIST O&M PAY - MAINT OF LINE TRANSFORMERS	E104	24,345.33	1.000000	24,345.33	
L_INC396000 - DIST O&M PAY - MAINT OF STREET LIGHTING & SIGNAL SYSTEMS	E508	4,222,133.97	1.000000	4,222,133.97	
L_INC397000 - DIST O&M PAY - MAINT OF METERS	E325	2,737,925.21	0.996099	2,727,245.39	
L_INC398000 - DIST O&M PAY - MAINT OF MISC DISTRI PLT	E104	617,369.49	1.000000	617,369.49	
L_INC401000 - CUST ACCT O&M PAY - SUPERVISION	I540	5,049,612.81	0.999993	5,049,576.33	
L_INC402000 - CUST ACCT O&M PAY - METER READING EXP	E330	3,360,791.16	0.999656	3,359,635.75	
L_INC403000 - CUST ACCT O&M PAY - CUST REC & COLLECT	E356	33,500,296.35	1.000000	33,500,296.35	
L_INC404000 - CUST ACCT EXP - UNCOLLECTIBLE ACCOUNTS	E205				
L_INC405000 - CUST ACCT O&M PAY - MISC CUSTOMER ACCOUNTS EXPENSES	E355				
L_INC407000 - CUST SERV & INFO PAY - SUPERVISION	E356	550,288.21	1.000000	550,288.21	
L_INC408000 - CUST SERV & INFO PAY - CUST ASSIST EXP	E356	1,692,901.63	1.000000	1,692,901.63	
L_INC409000 - CUST SERV & INFO PAY - INFO & INST ADV - GENERAL	E355				
L_INC410000 - CUST SERV & INFO PAY - MISC CUST SERV & INF	E356	4,778,271.44	1.000000	4,778,271.44	
L_INC411000 - SUPERVISION-SALES EXPENSES	E356				
L_INC510000 - DEMONSTRATING AND SELLING EXPENSES	E356				
L_INC516000 - MISC AND SELLING EXPENSES	E356	603,279.45	1.000000	603,279.45	
Total I900-LABOR-EXC-A&G		440,929,545.43		427,652,161.32	**0.969888**

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 20200007-EI
ENVIRONMENTAL COST RECOVERY CLAUSE
FPL SUPPLEMENTAL CAIR/MATS/CAVR FILING
APRIL 1, 2020

The discussion below provides FPL's current estimates of project activities and associated costs related to its Clean Air Interstate Rule ("CAIR") now the Cross State Air Pollution Rule ("CSAPR"), Mercury and Air Toxics Standards ("MATS"), which was formerly the Clean Air Mercury Rule ("CAMR") and Clean Air Visibility Rule ("CAVR")/Best Available Retrofit Technology ("BART") projects. FPL has completed all capital projects associated with installation of controls for compliance with these rules. Ongoing O&M and Capital parts replacement for these projects on existing units will continue in order to ensure compliance. Accordingly, FPL intends to address all ongoing CAIR/CAMR/CAVR projected and actual costs in FPL's annual ECRC filings, similar to all other environmental projects approved by the Commission, rather than filing a Supplemental CAIR/CAMR/CAVR report.

CAIR Compliance Project Update:

Status of CAIR (now CSAPR) Rule - On November 16, 2015, the EPA proposed the CSAPR Update Rule ("Update Rule") to address interstate transport of air pollution under the 2008 Ozone National Ambient Air Quality Standards ("NAAQS"). The proposed rule became final on September 7, 2016, significantly reducing ozone season nitrogen oxide ("NOx") emissions in many states using revised air quality data and updates based on reductions from use of cost-effective emission controls. In the final Update Rule, the EPA removed Florida from the cap-and-trade program because emissions from the State's utility units are now below the significance threshold for impacts to downwind ozone nonattainment areas. Several states have challenged

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 5
PARTY: MWS-1 (5)
DESCRIPTION: FPL Supplemental CAIR/MATS/
CAVR Filing

the EPA rule and the D.C. Circuit remanded the rule to EPA on October 1, 2019. FPL will continue working with the EPA to ensure that Florida and FPL are treated fairly in any proposed changes to CSAPR. Operation of controls installed under the CSAPR project that are required for compliance with other federal and state rules (e.g., Georgia Multi-Pollutant Rule) are ongoing as needed. Operations and maintenance of equipment associated with CSAPR are still required for installed equipment on operating units. Therefore, FPL continues to incur associated O&M project costs, as described below.

St. Johns River Power Park ("SJRPP") Selective Catalytic Reduction Systems ("SCR") and Ammonia Injection Systems - In January 2018, both SJRPP units were retired from service. Therefore, there will be no further operating expenditures on this activity.

Scherer SCR and Wet Flue Gas Desulfurization ("FGD") –While installation of the Scherer SCR and FGD controls have been completed, ongoing capital part replacements and O&M will continue to ensure continued operation of these emission controls to comply with the federal and state rules. FPL estimates its share of the Scherer Unit 4 CSAPR capital costs for projects planned in 2020 to be $5.536 million for replacement of the SCR.

For 2020, FPL has estimated its share of ongoing O&M expenses for operation of the SCR, FGD, and common plant facilities supporting the controls needed to comply with CSAPR to be $5.5 million. The O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment. O&M activities for the FGD include limestone consumption, limestone and by-product (gypsum)

handling operation, FGD operations, FGD tower and auxiliary equipment maintenance.

800 MW Unit Cycling Project - The 800 MW Cycling Project was implemented to allow FPL the ability to cycle the 800 MW units off-line when not needed to supply energy to meet system demand allowing FPL to reduce NOx emissions. FPL completed construction work associated with this project in 2011 at its Martin and Manatee plants. On December 31, 2018, FPL retired the Martin plant 800 MW units and no further expenditures are required for those units. For 2020, ongoing O&M expenses are $0.13 million for treatment of condenser tube fouling and maintenance of associated equipment at the Manatee 800 MW units.

Continuous Emissions Monitoring System ("CEMS") Plan for Gas Turbines ("GT") – There are no future projected capital or operating costs for the GT CEMS associated with this project. In December 2016, FPL completed the construction of peaking combustion turbines at the Lauderdale and Fort Myers plants, which replaced the generating capacity of the gas turbine peaking units at those plants. The 12 peaking gas turbines at Port Everglades have been decommissioned along with 22 gas turbines at Lauderdale and 10 gas turbines at Fort Myers plants. The remaining units are not subject to CEMS monitoring requirements. Accordingly, CEMS use has been discontinued.

Purchases of Allowances - To comply with the CSAPR and Acid Rain Program requirements, FPL must evaluate whether it holds sufficient allowances for compliance or needs to purchase additional allowances. FPL has determined that it holds sufficient Acid Rain sulfur dioxide ("SO_2") allowances in perpetuity for all of its fossil generating units. To a very limited extent, FPL

has been able to occasionally find a buyer for some of its excess allowances and has sold an immaterial amount of SO_2 Acid Rain allowances. Currently FPL's Plant Scherer Unit 4 is an affected unit under the CSAPR Rule for Georgia. FPL has determined that it has sufficient excess allowances to meet its annual compliance surrender obligations.

Actual CAIR/CSAPR capital costs through 2019 were $514.99 million.

CAIR/CSAPR CAPITAL COST ($Millions)		
Project	Total Project	2020 Projections
SJRPP-SCR/Ammonia Injection System	$55.02	$0.00
Scherer-SCR/FGD	$365.244	$5.536
800 MW Unit Cycling – Martin	$58.56	$0.00
800 MW Unit Cycling – Manatee	$36.16	$0.00

Actual CAIR/CSAPR O&M expenses through 2019 are $37.17 million.

CAIR/CSAPR O&M EXPENSE ($Millions)		
Project	Total Project	2020 Projections
SJRPP-SCR/Ammonia Injection System	$1.57	$0.00
Scherer-SCR/FGD	$31.07	$5.51
800 MW Unit Cycling – Martin	$4.44	$0.00
800 MW Unit Cycling – Manatee	$3.82	$0.13
CEMS at GTs	$0.46	$0.00
Allowances	($4.18)	($2.40)

Mercury Air Toxics Standards ("MATS") Compliance Project Update (formerly CAMR):

FPL is complying with the Mercury (or "Hg") reduction requirements of the Georgia Multipollutant Rule and the EPA's MATS rule by implementing the following projects identified previously under the CAMR project:

1. Installation of Fabric Filter Baghouse and Mercury Sorbent Injection System on Scherer Unit 4 (completed 2010).
2. Installation of HgCEMS on Scherer Unit 4 (completed 2009).
3. Installation of HgCEMS on SJRPP Units 1 and 2 (completed in 2008 and Units 1 and 2 retired in January, 2018).

Construction of the mercury monitoring equipment and mercury emission controls (Plant Scherer)

was completed in 2010. For 2020, FPL's share of costs for capital replacement parts for the projects at Scherer Unit 4 is estimated to be $1.106 million as capital replacement of components and controls. For 2020, FPL's share of ongoing MATS O&M expenses for Plant Scherer are projected to be $2.65 million, primarily for purchase and disposal of sorbents and replacement of bags as well as operation and maintenance of the Hg monitors.

In EPA's December 21, 2011 final MATS rule, oil-fired electric steam generating units were required to meet specific emission standards during oil combustion and demonstrate compliance through quarterly testing or continuous particulate emission monitoring systems. The rule's emission limits for oil operation had the effect of requiring electrostatic precipitators ("ESPs") for FPL's 800 MW oil-fired units. Construction of the ESPs was completed in 2014 with total capital costs for construction of the ESPs through 2018 at $209.82 million. As discussed earlier FPL's retirement of the Martin plant 800 MW units also removes the MATS compliance requirements and O&M costs for those units. For 2020, there are no forecasted capital costs for the Manatee plant 800 MW units but there is a planned maintenance outage of the Manatee Unit 1 ESP that was deferred from 2019.

Actual MATS capital costs through 2019 are $325.90 million.

MATS CAPITAL COSTS ($Millions)		
Project	Total Project	2020 Projections
Scherer-Sorbent Injection/Baghouse/ HgCEMS	$116.09	$1.106
800 MW ESP PMT	$209.82	$0.00

*FPL's share of the project costs

Actual MATS O&M expenses through 2019 are $23.48 million.

MATS O&M EXPENSE ($Millions)		
Project	Total Project	2020 Projections
SJRPP-Mercury CEMS	$0.33	$0.00
Scherer-Sorbent Injection/Baghouse/ HgCEMS	$19.90	$2.65
800 MW ESP PMT	$3.25	$0.26

CAVR / BART Project Update:

There are no future projected capital or operating costs for this project.

EPA's promulgation of the Clean Air Visibility Rule (CAVR) to address regional haze required affected sources to reduce visibility impacts to many of the U.S. National Parks and Monuments. FPL's retirement of Turkey Point Units 1 and 2, retirement of both combined cycle units at the

Putnam plant and installation of ESPs on the 800 MW units resulted in the Florida DEP finding that FPL had complied with the requirements of EPA's Regional Haze requirements.

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
Southeast Regional Office
263 13th Avenue South
St. Petersburg, Florida 33701-5505
http://sero.nmfs.noaa.gov

6/12/2019

F/SER31:AB

Kristin Eaton
Florida Power and Light Company
700 Universe Boulevard
Juno Beach, FL 33408

Dear Ms. Eaton:

On March 7, 2019, representatives from Florida Power and Light (FPL), the National Oceanic and Atmospheric Administration (NOAA Fisheries), and Florida Fish and Wildlife Conservation Commission (FWC) met to initiate discussion about the Fort Myers plant. As you are aware, the plant's operation has caused the deaths of five smalltooth sawfish (*Pristis pectinata*) over the past two years. The smalltooth sawfish is listed as endangered under the Endangered Species Act and it is unlawful for any person to take[1] the species within the United States (16 U.S.C. § 1538(a)(1)). It is therefore critical that FPL undertake measures to address the ongoing take at the plant and prevent future violation of the Act.

NOAA Fisheries wishes to collaborate with FPL to develop a solution. Building upon our discussions at the meeting, we believe the best way to prevent interactions with sawfish is to block their access to the intake canal. We recognize FPL's concerns that adding a structure at the canal entrance (e.g., something analogous to the grizzly bars currently in use at the pumps) could necessitate another system to keep the new structure free from debris. However, we believe that with proper design and placement of this structure along the edge of the river (away from the greatest intake velocity associated with the pumps), natural river or tidal flow could aid in keeping the structure clear.

We would like to further discuss this idea, or others, with FPL in order to prevent any further sawfish take. We appreciate your reporting the mortalities to FWC and look forward to your continued cooperation. To schedule the next meeting or conference call, please contact Mr. Adam Brame, NOAA Fisheries Sawfish Recovery Coordinator, at 727-209-5958 or adam.brame@noaa.gov.

Sincerely,

BERNHART.DAVID.M.1066125889
2019.06.12 11:45:19 -04'00'

David Bernhart
Assistant Regional Administrator
for Protected Resources

cc Jeffrey Moyer, FPL
Gregg Poulakis, FWC
Loren Remsberg, NOAA GCSE

[1] The term "take" means to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or to attempt to engage in any such conduct. 16 U.S.C. § 1532(19).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 6
PARTY: MWS-2 (6)
DESCRIPTION: June 12, 2019 NOAA Letter to FPL

United States Department of the Interior
U. S. FISH AND WILDLIFE SERVICE
7915 BAYMEADOWS WAY, SUITE 200
JACKSONVILLE, FLORIDA 32256-7517

IN REPLY REFER TO:

March 25, 2020

Mr. Sean Chase
Florida Power and Light
6000 US1 North
Cocoa, FL 32927

Dear Mr. Chase:

On January 26 and February 10, 2020, the U.S. Fish and Wildlife Service's North Florida Ecological Services Office (NFESO) was notified of two additional Florida manatee (*Trichechus manatus latirostris*) carcasses that had been discovered in the intake wells at Florida Power and Light's (FPL) Cape Canaveral Energy Center (CCEC) in Port St. John, Florida. In the last four months, four manatee carcasses have been discovered in or near the intake wells. From 2013 through November 2019, there have been 31 other carcasses reported in or near the intake wells (FWC-FWRI manatee mortality database, 2020). While in some cases, it was unclear if the manatee died within the intake well or if the carcass was carried into the intake by water movement at the plant, the Florida Fish and Wildlife Conservation Commission's (FWC) Marine Mammal Pathobiology Laboratory was able to confirm that at a minimum, the intake suction was a likely causal factor for some of the manatees discovered in the wells.

We appreciate the efforts by FPL since 2013, to eliminate Florida manatee mortality at this plant; however, these efforts have not been successful. Florida manatees are protected under the Endangered Species Act (1973) and the Marine Mammal Protection Act (1972), and it is very important that this issue be addressed. There have been a number of meetings and teleconferences between FPL, FWC, and NFESO staff (most recently on February 11, 2020) in a continuing effort to identify a solution to this issue. It is critical that FPL continue to evaluate and implement corrective measures to address the take at the plant.

FPL has been a significant partner in Florida manatee conservation efforts, and I urge your continued support as our staffs work together to resolve this issue. Terri Calleson of my staff is the point of contact for my office and her number is (904) 731-3286.

Sincerely,

Jay B. Herrington
Field Supervisor

cc:
Ron Mezich, FWC
Jodie Eldridge, FPL
Kristin Eaton, FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 7
PARTY: MWS-3
DESCRIPTION: March 25, 2020 USFWS Letter to FPL

MIAMI-DADE COUNTY, through its DEPARTMENT OF REGULATORY AND ECONOMIC RESOURCES, DIVISION OF ENVIRONMENTAL RESOURCES MANAGEMENT,

Complainant,

v.

FLORIDA POWER & LIGHT COMPANY,

Respondent.
_____/

CONSENT AGREEMENT

This Consent Agreement, entered into by and between the Complainant, MIAMI-DADE COUNTY, through its DEPARTMENT OF REGULATORY AND ECONOMIC RESOURCES, DIVISION OF ENVIRONMENTAL RESOURCES MANAGEMENT ("DERM"), and the Respondent FLORIDA POWER & LIGHT COMPANY ("FPL"), pursuant to Section 24-7(15)(c) of the Code of Miami-Dade County, shall serve to redress alleged violations of Chapter 24 of the Code of Miami-Dade County located near, surrounding, or in the vicinity of the Cooling Canal System located at Turkey Point on FPL's property, as further described herein, in Miami-Dade County, Florida.

DERM and FPL enter into the following Consent Agreement:

FINDINGS OF FACT

1. DERM is a division of Miami-Dade County, a political subdivision of the State of Florida, which is empowered to control and prohibit pollution and protect the environment within Miami-Dade County pursuant to Article VIII, Section 6 of the Florida Constitution, the Miami-Dade County Home Rule Charter and Section 403.182 of the Florida Statutes.

2. Florida Power & Light Company ("FPL") is the owner and operator of the Turkey Point Power Plant, and FPL is the owner and operator of approximately a 5,900-acre network of unlined canals (the "Cooling Canal System" or "CCS") on the FPL property described in the map in Exhibit A (the "Property").

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 8
PARTY: MWS-4
DESCRIPTION: 2015 Consent Agreement

3. In 1971, FPL signed a Consent Decree with the U.S. Department of Justice that required the construction, after permitting, of a closed-loop cooling configuration, with no discharge to surface waters.

4. The Florida Department of Pollution Control (later to become the Florida Department of Environmental Protection), in 1971, issued Construction Permit No. IC-1286 for the CCS. In 1972, Dade County issued Zoning Use Permit No. W-49833 for the excavation of the proposed Alternate Cooling Water Return Canal. FPL represents that in 1973, the construction of the CCS was completed; and the CCS was closed from the surface waters of both Biscayne Bay and Card Sound, becoming a closed-loop system.

5. An approximate 18 foot deep interceptor ditch located along the west side of the CCS was designed and constructed to create a hydraulic barrier to keep water in the CCS from migrating inland or westward.

6. In 1972, FPL entered into an agreement with the Central and Southern Florida Flood Control District (later to become the South Florida Water Management District or "District") addressing the operations and impacts of the CCS. The agreement has been updated several times, with the most recent version being the Fifth Supplemental Agreement between the District and FPL entered into on October 16, 2009 ("Fifth Supplemental Agreement") which included an extensive monitoring program for the CCS, entitled the Turkey Point Plant Groundwater, Surface Water and Ecological Monitoring Plan ("2009 Monitoring Plan"), incorporated as Exhibit A of the Fifth Supplemental Agreement.

7. In a letter dated April 16, 2013, the District notified FPL of their determination that saline water from the CCS has moved westward of the L-31E Canal in excess of those amounts that would have occurred without the existence of the CCS, and pursuant to the provisions of the Fifth Supplemental Agreement, initiated consultation with FPL for the mitigation, abatement or remediation of the saline water movement.

8. DERM issued a Notice of Violation dated October 2, 2015 (the "NOV") to FPL, alleging violations of Chapter 24 of the Code of Miami-Dade County, for alleged violations of County water quality standards and criteria in groundwater attributable to FPL's actions, and specifically for groundwaters outside the boundaries of FPL's Cooling Canal System and beyond the boundaries of the Property.

9. The phrase "hypersaline water" as used herein is defined as water that exceeds 19,000 mg/L chlorides.

10. DERM maintains there is hypersaline water attributable to FPL's actions in the groundwaters outside the boundaries of the Property, which exceeds County water quality standards and criteria. FPL acknowledges the presence of hypersaline water in certain areas outside the boundaries of the Property. For waters that do not reach the level of hypersalinity, DERM and FPL do not agree on the applicable "background" standards for chlorides.

11. In 2013 and 2014, FPL experienced water quality issues within the CCS, including increases in temperature and salinity, and FPL sought approvals from various regulatory agencies for actions to improve the water quality within the CCS.

12. DEP issued an Administrative Order, No. 14-0741, on December 23, 2014, requiring FPL to, among other things, reduce and maintain the annual average salinity of the CCS at a practical salinity of 34, and that Administrative Order is currently the subject of an Administrative Hearing.

13. Both DERM and FPL agree and acknowledge that it would be beneficial to improve the water quality within the Cooling Canal System itself, and FPL has already undertaken some efforts to improve the CCS water quality.

14. This Consent Agreement requires FPL to take action to address the County's alleged violations of County water quality standards and criteria in groundwaters outside the CCS as described in the NOV. As part of these actions, this Consent Agreement also requires FPL to take into account its efforts to improve CCS water quality and the potential and actual impacts of such actions on water resources outside the CCS, to not cause or contribute to (i) the exacerbation of alleged violations of County water quality standards or criteria or (ii) future violations of County water quality standards or criteria in the groundwaters or surface waters outside the CCS.

15. FPL hereby agrees to the terms of this Consent Agreement without admitting the allegations made by the above-mentioned NOV.

16. In an effort to expeditiously resolve this matter and to ensure compliance with Chapter 24 of the Code of Miami-Dade County, and to avoid time consuming and costly litigation, the parties hereto agree to the following, and it is ORDERED:

REQUIREMENTS

17. FPL shall undertake the following activities to specifically address water quality impacts associated with the CCS, as alleged in the NOV. The objective of this Consent Agreement will be for FPL to demonstrate a statistically valid reduction in the salt mass and volumetric extent of hypersaline water (as represented by chloride concentrations above 19,000 mg/L) in groundwater west and north of FPL's property without creating adverse environmental impacts. A further objective of this Consent Agreement is to reduce the rate of, and, as an ultimate goal, arrest migration of hypersaline groundwater. Recognizing other factors beyond FPL's control may influence movement of groundwater in the surficial aquifer, FPL shall reasonably take into account such factors when developing and implementing remedial actions to minimize the timeframe for achieving compliance with this Consent Agreement.

a. Abatement.

i. DERM acknowledges that FPL is planning to undertake the following:

1. pursue permitting, construction and operation of up to six Upper Floridan Aquifer System wells in accordance with the Site Certification Modification that is the subject of DOAH Case No. 15-1559EPP.

2. continue the use of the existing marine wells (SW-1, SW-2, and PW-1) as a short term resource to lower and maintain salinities. FPL shall work to avoid the use of the marine wells, except under extraordinary circumstances.

3. continue operation of the authorized L-31E canal pumps as a short term resource only, in accordance with the terms and conditions of the applicable approvals. FPL acknowledges that the use of water from the L-31E canal is intended only as a short term resource to lower CCS salinity. FPL anticipates the need for this resource for the next two years to reduce salinity as it transitions into the long term resources that are intended to maintain the lower salinity in the CCS. FPL acknowledges that additional regulatory

approvals will be required for continuation of this activity beyond the expiration of the existing approvals.

ii. FPL shall evaluate alternative water sources to offset the CCS water deficit and reduce chloride concentration in the CCS, and as a means of abating the westward movement of CCS groundwater. FPL will consider the practicality and appropriateness of using reclaimed wastewater from the Miami-Dade County South District Waste Water Treatment Plant as an alternative water source. FPL will provide DERM a summary of its Alternative Water Supply plan within 180 days of executing the Consent Agreement. FPL recognizes the importance and potential for reuse water, and FPL will make good faith efforts to implement the use of reuse water where practicable.

iii. FPL shall also conduct a review of the Interceptor Ditch operations to determine if current design and/or operations can be practicably modified to improve its function recognizing the current status of the CCS and surrounding wetlands. FPL will provide a summary of its Interceptor Ditch Review within 180 days of executing the Consent Agreement.

iv. The alternative water sources and any modifications to Interceptor Ditch design or operation shall be authorized through the appropriate regulatory processes and shall be demonstrated to not create adverse impacts to surface waters, groundwater, wetland or other environmental resources consistent with the Fifth Supplemental Agreement.

b. Remediation. FPL shall develop and implement the following actions to intercept, capture, contain, and retract hypersaline groundwater (groundwater with a chloride concentration of greater than 19,000 mg/L) to the Property boundary to achieve the objectives of this Consent Agreement.

i. Phase 1. FPL shall design, permit, and construct a Biscayne Aquifer Recovery Well System (RWS) based on the results of a variable density dependent groundwater model which shall be sufficient to support the design of the RWS to intercept, capture, and contain the hypersaline plume; support authorization through the appropriate regulatory processes; and demonstrate that it will not create adverse

impacts to groundwater, wetland (hydroperiod or water-stage), or other environmental resources. Final operation and design will be informed by an Aquifer Performance Test (APT). FPL shall provide its design and supporting information for the Recovery Well System and associated monitoring wells for DERM review and approval within 180 days of executing the Consent Agreement. FPL shall proceed with implementation within one year of executing the Consent Agreement, subject to regulatory timelines not in FPL's control. The initial design will be based on up to 12 MGD disposal capacity recognizing existing on-site capability. Efficacy of this design constraint will be reviewed in Phases 2, 3, and 4.

ii. Phase 2. FPL shall operate the RWS in accordance with all local, state, and federal regulatory requirements, collect data as required by the monitoring program, and employ the data to inform and reduce the uncertainty of the groundwater model. Status and efficacy of the system operation in meeting the objectives of this Consent Agreement and results of continued groundwater model refinement will be provided in the annual reports required in Paragraph 17d.

iii. Phase 3. After five years, FPL shall evaluate the effectiveness of the RWS in achieving the goal to intercept, capture, contain, and ultimately retract the hypersaline groundwater plume. This evaluation shall include estimated milestones and be based on the results of the monitoring data and refined groundwater/surfacewater model, which will be submitted to DERM. If the analysis indicates that the RWS is not anticipated to achieve the goal to intercept, capture, contain, and ultimately retract the hypersaline groundwater plume, FPL shall make recommendations for modifications to the project components and/or designs to ensure the ability of the system to achieve the objectives of the Consent Agreement. The evaluation and any proposed revisions shall be submitted to DERM for review and approval.

iv. Phase 4. After ten years, FPL shall review the results of the activities and progress to achieve the objectives of this Consent Agreement, and this evaluation shall be submitted to DERM. If monitoring demonstrates that the activities are not achieving the objectives of this Consent Agreement, FPL shall revise the project components and/or designs to ensure the ability of the system to achieve the objectives of this

Consent Agreement. The proposed revisions shall be submitted to DERM for review and approval.

c. Regional Hydrologic Improvement Projects. In addition, FPL agrees to undertake the following:

i. Raise control elevations in the Everglades Mitigation Bank. Within 30 days of the effective date of this Consent Agreement, FPL shall raise the control elevations of the FPL Everglades Mitigation Bank ("EMB") culvert weirs to no lower than 0.2 feet lower than the 2.4 foot trigger of the S-20 structure and shall maintain this elevation. After the first year of operation, FPL shall evaluate the change in control elevation, in regards to improvements in salinity, water quality, and lift in the area, and if FPL determines that the change in control elevations is not effective, or that FPL is negatively impacted in receiving mitigation credits as a result of this action, FPL will consult with DERM and propose potential alternatives.

ii. Fill portions of the Model Lands North Canal within the Everglades Mitigation Bank. Within 30 days of the effective date of the Consent Agreement, FPL shall seek all necessary regulatory approvals to place excavated fill from the adjoining roadway into the Model Lands North Canal within FPL's Everglades Mitigation Bank. Upon issuance of such regulatory approvals, FPL shall, starting on the east end, fill the Model Lands North Canal. This Consent Agreement only requires FPL to fill to the extent the fill is available from the adjoining roadway permitted to be degraded.

iii. If the District determines that flowage easements are needed from FPL in order to increase the operational stages of the S-20 water control structure as planned and approved by CERP, FPL agrees to provide such flowage easements for FPL owned land within the Everglades Mitigation Bank, in favor of the District within six months of the determination.

iv. FPL acknowledges the benefit of hydrologic restoration projects contemplated by the Comprehensive Everglades Restoration Project ("CERP"), as well as other government entities, adjacent and to the west of the CCS in controlling movement of hypersaline and saline waters in the Biscayne Aquifer. FPL commits to working with

local, state and federal agencies to facilitate implementation of these projects to promote improved hydrologic conditions.

d. Monitoring and Reporting. FPL shall conduct monitoring to evaluate the progress made in achieving the objectives of this Consent Agreement. This includes actions that result from satisfying the abatement, remediation and hydrologic improvement components of this Consent Agreement. FPL shall initiate the monitoring and reporting requirements identified below within 30 days of executing the Consent Agreement. The monitoring shall include the following:

i. FPL shall facilitate DERM access to all data from continuous electronically monitored stations.

ii. FPL shall continue to provide monthly and quarterly reports substantially consistent with those required in M-D Class I permit CLI-2014-0312, beyond the expiration of the permit.

iii. FPL shall employ Continuous Surface Electromagnetic Mapping (CSEM) methods to assess the location and orientation of the hypersaline plume west and north of the CCS.

iv. FPL shall add three groundwater monitoring clusters (shallow, mid and deep) to monitor groundwater conditions in the model lands basin. The well clusters shall be similar in design and function to existing groundwater monitoring wells in the region as part of the CCS monitoring program, and shall be geographically located in consultation with DERM.

v. FPL shall submit annual reports providing an evaluation of progress in achieving the objectives of this Consent Agreement, status of implementing projects identified above, and the results of monitoring to determine the impacts of these activities. Recommendations for refinements to the activities will be included in the annual report. This may include deletions of monitoring that is demonstrated to no longer be needed, or additional monitoring that is warranted based on observations.

SAFETY PRECAUTIONS

18. FPL shall maintain the subject property during the pendency of this Consent Agreement in a manner which shall not pose a hazard or threat to the public at large or the environment and shall not cause a nuisance or sanitary nuisance as set forth in Chapter 24 of the Code of Miami-Dade County, Florida.

VIOLATION OF REQUIREMENTS

19. This Consent Agreement constitutes a lawful order of the DERM Director and is enforceable in a civil court of competent jurisdiction. Violation of any requirement of this Consent Agreement may result in enforcement action by DERM. Each violation of any of the terms and conditions of this Consent Agreement by FPL shall constitute a separate offense.

SETTLEMENT COSTS

20. FPL hereby certifies that it has the financial ability to comply with the terms and conditions herein and to comply with the payment of settlement costs specified in this Agreement.

21. DERM has determined that due to the administrative costs incurred by DERM for this matter, a settlement of $30,000.00 is appropriate. FPL shall, within sixty (60) days of the effective date of this Consent Agreement, submit to DERM a check in the amount of $30,000.00 for full settlement payment. The payment shall be made payable to Miami-Dade County and sent to the Division of Environmental Resources Management, c/o Barbara Brown, 701 NW 1st Court, 6th Floor, Miami, FL 33136-3912.

22. In the event that FPL fails to submit, modify, implement, obtain, provide, operate and/or complete those items listed in paragraph 17 herein, FPL shall pay DERM a civil penalty of one hundred dollars ($100.00) per day for each day of non-compliance and FPL may be subject to enforcement action in a court of competent jurisdiction for such failure pursuant to those provisions set forth in Chapter 24 of the Code of Miami-Dade County. Any such payments shall be made by FPL to DERM within ten days of receipt of written notification and shall be sent to the Division of Environmental Resources Management, 701 NW 1st Court, 6th Floor, Miami, FL 33136-3912.

GENERAL PROVISIONS

23. FPL shall allow any duly authorized representative of DERM, with reasonable notification, to enter and inspect the CCS, Floridan wells, extraction wells, or any other relevant facilities, at any reasonable time for the purpose of ascertaining the state of compliance with the terms and conditions of this Consent Agreement. DERM shall comply with the plant safety and security precautions. FPL shall provide and maintain a point of contact at the Turkey Point Power Plant to assist DERM in accessing the facilities to be inspected.

24. On a quarterly basis (January, April, July, and October), DERM may collect surface and/or groundwater samples at the discretion of DERM at various monitoring locations in accordance with monitoring referenced in Paragraph 17 above.

25. FPL and DERM agree to cooperate and use best efforts moving forward related to this Consent Agreement.

26. Disputes related to or arising out of this Consent Agreement shall be construed consistent with the laws of the State of Florida and the United States, as applicable, and shall be filed in the state or federal courts of the State of Florida, as appropriate. Proceedings shall take place exclusively in the Circuit Court for Miami-Dade County, Florida or the United States District Court for the Southern District of Florida.

27. In consideration of the complete and timely performance by FPL of the obligations contained in this Consent Agreement, DERM waives its rights to seek judicial imposition of damages or civil penalties for the matters alleged in Notice of Violation and Consent Agreement.

28. Where FPL cannot meet timetables or conditions due to circumstances beyond FPL's control, FPL shall provide written documentation to DERM which shall substantiate that the cause(s) for delay or non-compliance was not reasonably in FPL's control. DERM shall make a determination of the reasonableness of the delay for the purpose of continued enforcement pursuant to paragraph 22 of this Consent Agreement.

29. DERM expressly reserves the right to initiate appropriate legal action to prevent or prohibit future violations of applicable laws, regulations, and ordinances or the rules promulgated thereunder.

30. Entry of this Consent Agreement does not relieve FPL of the responsibility to comply with applicable federal, state or local laws, regulations, and ordinances.

31. FPL acknowledges that this Consent Agreement is within the jurisdiction of Miami-Dade County. Nothing in this Consent Agreement is intended to expand, nor shall this Consent Agreement be construed to expand, the regulatory authority or jurisdiction of Miami-Dade County.

32. This Consent Agreement shall neither be evidence of a prior violation of this Chapter nor shall it be deemed to impose any limitation upon any investigation or action by DERM in the enforcement of Chapter 24 of the Code of Miami-Dade County.

33. This Consent Agreement shall become effective upon the date of execution by the DERM Director, or the Director's designee.

October 6, 2015
Date

Eric E. Silagy
President & CEO
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Respondent

Before me, the undersigned authority, personally appeared Eric Silagy, who after being duly sworn, deposes and says that they have read and agreed to the foregoing.

Subscribe and sworn to before me this 6th day of October, 2015 by Eric Silagy (name of affiant).

Personally known ✓ or Produced Identification _____.
(Check one)

Type of Identification Produced: _____.

LISA GROVE
MY COMMISSION # FF 154741
EXPIRES: December 14, 2016
Bonded Thru Budget Notary Services

Lisa Grove
Notary Public Signature

Lisa Grove
Notary Public Printed Name

DO NOT WRITE BELOW THIS LINE – GOVERNMENT USE ONLY

OCT 7, 2015
Date

Lee N. Hefty, DERM Director
Miami-Dade County

Witness

Barbara Brown
Witness


Exhibit A
FPL Turkey Point Property Boundary
for Purposes of Consent Agreement (~9000 acres)
0
0.5
1
2
Miles
2015_FPL_TP_facility_bnd90K.mxd - October 6, 2015

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION v. FLORIDA POWER & LIGHT COMPANY,	)	IN THE OFFICE OF THE SOUTHEAST DISTRICT OGC FILE NO. 16-0241

CONSENT ORDER

This Consent Order ("Order") is entered into between the State of Florida Department of Environmental Protection ("Department") and Florida Power & Light Company ("Respondent" or "FPL") to reach settlement of certain matters at issue between the Department and Respondent.

The Department finds:

1. The Department is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources and to administer and enforce the provisions of Chapter 403, Florida Statutes ("F.S."), and the rules promulgated and authorized in Title 62, Florida Administrative Code ("F.A.C."). The Department has jurisdiction over the matters addressed in this Order.

2. FPL is a "person" as defined under Section 403.031(5), F.S.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 9
PARTY: MWS-5
DESCRIPTION: June 2016 FDEP Consent Order

3. FPL owns and operates a cooling canal system ("CCS"), an approximately 5,900-acre network of unlined canals at Turkey Point Power Plant. FPL began construction of the CCS in 1972. Turkey Point originally obtained cooling water for the facility by drawing surface water from an intake channel connected to Biscayne Bay, and discharging that water, after it had been heated, into Biscayne Bay and Card Sound through a series of discharge canals. In 1971, FPL entered into a Final Judgment with the U.S. Department of Justice that required the permitting, construction, operation, and maintenance of a closed-loop cooling canal configuration with limitations on makeup and blowdown water.

4. FPL is the permittee and operates the CCS under National Pollutant Discharge Elimination System/Industrial Wastewater Permit Number FL0001562 (the "Permit"). This Permit is issued pursuant to the federal NPDES program and Florida industrial wastewater permitting program. The Permit authorizes wastewater discharges from the generating units through two internal outfalls into the CCS. The Permit does not authorize direct discharges to surface waters of the state. The Permit authorizes discharges from the CCS into Class G-III groundwater which is part of the surficial aquifer system. Condition IV.1 of the Permit provides that discharges to groundwater shall not cause a violation of the minimum criteria for ground water specified in Rules 62-520.400, F.A.C. and 62-520.430, F.A.C. Rule 62-520.400, F.A.C., provides that discharges to ground water shall not impair the reasonable and beneficial use of adjacent waters, either ground or surface.

5. Turkey Point Power Plant Units 3 through 5 are licensed under the Florida Power Plant Siting Act, Chapter 403, Part II, F.S. Those units operate in accordance with the conditions of certification in their license, PA 03-45. Condition of Certification X requires FPL to execute a 5th Supplemental Agreement with the South Florida Water Management District ("SFWMD") and to revise FPL's monitoring obligations, which resulted in the Turkey Point Plant Groundwater, Surface Water and Ecological Monitoring Plan, as amended, ("2009 Monitoring Plan") incorporated as Exhibit A to the Fifth Supplemental Agreement between the South Florida Water Management District and FPL entered on October 16, 2009.

6. Historical data show that, when the CCS was constructed in the 1970's, saline water had already intruded inland along the coast due to many factors such as freshwater withdrawals, drought, drainage and flood control structures, and other human activities. To date, the relative contributions of the different factors toward westward movement of the saltwater interface have not been fully identified.

7. FPL provided information on action they have already taken on several fronts to address the broader regional risks and the many causes of saltwater intrusion. In 2010, FPL installed a gated culvert approximately 3.8 miles inland of Biscayne Bay in the Card Sound Road Canal to eliminate an unrestricted inland conveyance of saltwater from the bay. Also, in 2014, FPL installed a broad, fix crested weir in the S-20 Discharge Canal to prevent the historic migration of bay saltwater up to the S-20 Canal.

8. The phrase "hypersaline water/plume" as used in this Order means water that exceeds 19,000 mg/L chlorides. The term "saltwater interface" ("SWI") as used in this Order means the intersection of class G-II and G-III groundwaters.

9. The CCS includes an approximately 18 foot deep interceptor ditch along the western edge of the CCS. As approved and constructed, the interceptor ditch system has been effective at restricting the westward movement of the saline water from the CCS in the upper portion of the aquifer but has not restricted the westward movement of saline waters into the deeper portions of the aquifer. Saline water from the CCS has moved, at depth, westward of the L-31E Canal in excess of those amounts that would have occurred without the existence of the CCS.

10. The Department issued an Administrative Order (OGC No. 14-0741) to FPL related to the CCS at Turkey Point on December 23, 2014 and made final by an Order of the Department issued on April 21, 2016. The Administrative Order requires FPL to reduce the salinity in the CCS. This Consent Order supersedes all of the requirements of that Administrative Order.

11. FPL conducted or implemented dredging, vegetation control, water stage management, and chemical additives to the CCS to maintain the thermal efficiency of the system and to control salinity and temperature.

12. Elevated salinity levels in the CCS cause, or at a minimum contribute to, the hypersaline discharges into the groundwater. Reducing the CCS surface water salinity from an elevated base salinity condition will require certain measures such as a greater

addition of relatively fresher water, removal of salt mass from the CCS, and management of CCS inflows and outflows. Ambient weather factors, such as precipitation amounts, temperatures, and regional water levels can also affect CCS salinity levels.

13. On October 7, 2015, FPL entered into a Consent Agreement with Miami-Dade County to resolve a Notice of Violation from the County dated October 2, 2015. Pursuant to paragraph 17 of the Consent Agreement, the objective is for FPL to demonstrate a statistically valid reduction in the salt mass and volumetric extent of the hypersaline water (as represented by chloride concentrations above 19,000 mg/L) in groundwater west and north of FPL's property without creating adverse environmental impacts. A further objective of the Consent Agreement is to reduce the rate of and, as an ultimate goal, arrest migration of hypersaline groundwater.

14. On April 25, 2016, the Department issued a Notice of Violation (OGC File No.: 16-0241) ("NOV") to FPL stating that the CCS is the major contributing cause to the continuing westward movement of the saline water interface, and that the discharge of hypersaline water contributes to saltwater intrusion. In the NOV, the Department found that saltwater intrusion into the area west of the CCS is impairing the reasonable and beneficial use of adjacent G-II groundwater in that area. FPL has operated the CCS under regulatory approvals, and the Department has not previously issued FPL either a Warning Letter or a Notice of Violation concerning FPL's operation of the CCS.

15. On April 25, 2016, the Department issued a Warning Letter, #WL 16-000151W13SED, to FPL concerning sampling events that indicated that ground water

originating from beneath the CCS is reaching tidal surface waters connected to Biscayne Bay in artificial deep channels immediately adjacent to the CCS. The Warning Letter requested that FPL provide facts to assist in determining whether any violations of Florida law have occurred.

16. The NOV directed FPL to enter into consultations to develop a consent order to, at a minimum, remediate the CCS contribution to the hypersaline plume, reduce the size of the hypersaline plume, and prevent future harm to waters of the State. FPL entered into consultations with the Department as required by the Orders for Corrective action in the NOV. The consultations resulted in resolutions to address the violations alleged in the NOV and issues raised in the Warning Letter, as memorialized in this Order.

17. On May 16, 2016, FPL submitted to the Department the nutrient monitoring results from certain surface water monitoring stations in deep channels adjacent to the CCS for total nitrogen, total phosphorous, TKN, and chlorophyll a. The Department reviewed the information by FPL and determined that no exceedances of surface water quality standards were detected in Biscayne Bay monitoring. This Order is intended to minimize the potential for future exceedances.

18. This Order and FPL's compliance with the requirements set forth in this Order address issues identified in the Department's Warning Letter, Administrative Order and NOV.

Respondent and the Department mutually agree and it is

ORDERED:

19. The first objective of this Order is for FPL to cease discharges from the CCS that impair the reasonable and beneficial use of the adjacent G-II ground waters to the west of the CCS in violation of Condition IV.1 of the Permit and Rule 62-520.400, F.A.C. FPL shall accomplish this first objective by undertaking freshening activities as authorized in the Turkey Point site certification, by eliminating the CCS contribution to the hypersaline plume, by maintaining the average annual salinity of the CCS at or below 34 Practical Salinity Units ("PSU"), by halting the westward migration of hypersaline water from the CCS, and by reducing the westward extent of the hypersaline plume to the L-31E within 10 years, thereby removing its influence on the saltwater interface, without creating adverse environmental impacts. The second objective of this Order is for FPL to prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards in Biscayne Bay. FPL shall accomplish this second objective primarily by undertaking restoration projects in the Turtle Point Canal and Barge Basin area. The third objective of this Order is for FPL to provide mitigation for impacts related to the historic operation of the CCS, including but not limited to the hypersaline plume and its influence on the saltwater interface.

20. To achieve the first objective of this Order, FPL shall:

a. Achieve a CCS average annual salinity of at or below 34 PSU ("threshold") at the completion of the fourth year of freshening activities, which are authorized by the Turkey Point site certification modification. If FPL fails to reach an annual average salinity of at or below 34 PSU by the end of the fourth year of freshening activities, within 30 days of failing to reach the required threshold, FPL shall submit a plan to the Department detailing additional measures, and a timeframe, that FPL will implement to achieve the threshold. Subsequent to attaining the threshold in the manner set forth above, if FPL fails more than once in a 3 year period to maintain an average annual salinity of at or below 34 PSU, FPL shall submit, within 60 days of reporting the average annual salinity, a plan containing additional measures that FPL shall implement to achieve the threshold salinity level.

b. Submit a thermal efficiency plan within 180 days of the effective date of the Order that shall include a detailed description for the CCS to achieve a minimum of 70 percent thermal efficiency. This efficiency plan shall address water stage management, vegetation control, dredging, chemical additives to the CCS for facility operation, and upset recovery. FPL shall implement the efficiency plan within 90 days of being instructed to do so by the Department.

c. Implement a remediation project that shall include a recovery well system that will halt the westward migration of hypersaline water from the CCS within 3 years and reduce the westward extent of the hypersaline plume to the L-31E canal within 10 years without adverse environmental impacts.

i. Within 30 days of the effective date of this Order, provide the Department with available detailed plans for this remediation project, including supporting data, that are designed to halt the westward migration of the hypersaline plume within 3 years of commencement of the remediation project and retract the hypersaline plume to the L-31E canal within 10 years of the commencement of the remediation project. Location, volume and movement of the hypersaline plume shall be determined by Continuous Surface Electromagnetic Mapping ("CSEM") technology as detailed below.

ii. Apply for appropriate regulatory approvals within 90 days of the effective date of this Order and begin construction of this remediation project within 30 days after receipt of all necessary regulatory approvals. FPL shall advise the Department of any modifications to the submitted plans that result from regulatory reviews. FPL shall commence the operation of this remediation project upon completion of construction. FPL shall provide the Department with written notice of the date FPL commenced operation of this remediation project.

iii. For determining compliance, the westward migration of the hypersaline plume shall be deemed halted if the third CSEM survey shows no net increase in hypersaline water volume and no net westward movement in the leading edge of the hypersaline plume.

iv. To ensure overall remediation objectives are attained in a timely manner, if the second CSEM survey indicates that the net westward migration of

the hypersaline plume is not being halted, then, within 180 days of the second CSEM survey, FPL shall develop and submit for approval to the Department a plan with specific actions to achieve the objectives of the remediation project. If the third CSEM survey still indicates the net westward migration of the hypersaline plume has not halted, FPL shall implement the approved additional measures within 30 days after submittal of the third CSEM report to the Department.

v. At the conclusion of the fifth year of operation of the remediation project, FPL shall evaluate and report to the Department, within 60 days, the effectiveness of the system in retracting the hypersaline plume to the L-31E canal within 10 years. If this report shows the remediation project will not retract the hypersaline plume to the L-31E canal within 10 years due to adverse environmental impacts of remedial measures or other technical issues, FPL shall provide an alternate plan for Department review and approval. FPL shall begin implementing the alternate plan within 30 days of receipt of notice that the alternate plan has been approved.

21. To achieve the second objective of this Order, FPL shall:

a. Complete Barge Basin and Turtle Point Canal restoration projects within 2 years of receiving the final regulatory approval. Within 60 days of the effective date of this Order, FPL shall provide the Department with a detailed plan and design of the restoration projects to prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards in Biscayne Bay. Not more than 90 days after the effective date of this Order,

FPL shall prepare and submit permit applications to relevant regulatory agencies (including the Department, the United States Army Corp of Engineers, and Miami-Dade County, as necessary) to address the restoration of the Turtle Point Canal and Barge Basin. Project success shall be based on full project completion and monitoring results of surface water sampling sites TPBBSW-4, TPBBSW-10, and TPBBSW-7T.

b. Within 90 days of the effective date of this Order, submit a detailed report outlining the potential sources of the nutrients found in the CCS, including chemical products used for plant operations. The report shall include a plan for minimizing nutrient levels in the CCS, which shall be implemented within 90 days after being instructed to do so by the Department.

c. Within 120 days of the effective date of this Order, conduct a thorough inspection of the CCS periphery including all dams, dikes, berms, and appurtenant structures using sound engineering judgment and best practices. FPL shall submit a detailed report to the Department of the inspection results, including underlying data. The inspection must be conducted by an independent qualified Florida licensed professional engineer. The term qualified means having successfully completed the Mine Safety and Health Administration Qualification for Impoundment Inspection course in addition to the Annual Retraining for Impoundment Qualification, or equivalent qualifications. The engineer shall also review available documentation and include in the report any actions necessary to ensure the integrity of the CCS. If the inspection identifies a material breach or structural defect in a peripheral levee of the CCS, FPL shall, within

60 days, submit a detailed description of the plan to address any material breaches or structural defects. FPL shall implement the plans to address any material breaches or structural defects within 60 days of the report mandated under this paragraph.

22. If FPL seeks renewal of the Combined License for either Unit 3 or 4 from the Nuclear Regulatory Commission, FPL shall provide the Department any information provided to the NRC detailing the future operating viability, including environmental and natural resource impacts, of the CCS and any potential alternative cooling technologies during the second renewal period.

23. To achieve the third objective of this Order, FPL shall undertake the following:

a. Complete an analysis, within 2 years from the effective date of this Order, with input from the Department and other agencies as selected by the Department, using the variable density three dimensional groundwater model developed under the Miami-Dade County Consent Agreement, that seeks to allocate relative contributions of other entities or factors to the movement of the SWI.

b. Enter into an agreement within 1 year with SFWMD, if SFWMD requests, to convey to SFWMD, FPL property interests in essential properties within the Biscayne Bay Coastal Wetlands Phase I project to facilitate the Comprehensive Everglades Restoration Plan in exchange for payment based on a jointly approved appraisal process or other mutually agreeable considerations. (See Attachment A).

c. Deposit $1.5 million into a Florida Department of Financial Services escrow account in accordance with an escrow agreement signed by FPL, the Department and the Florida Department of Financial Services. The escrow account shall be used to finance projects in the Turkey Point region that support mitigation of saltwater intrusion.

d. Conduct grab sampling within 90 days of the effective date of this Order, to improve trend analysis in Biscayne Bay and Card Sound surface waters, every two months, taking both top and bottom samples, for two years from the effective date of this Order at six sites as shown in Attachment B. The parameters sampled shall be: temperature, conductivity, pH, dissolved oxygen, turbidity, salinity, tritium, ammonia, nitrate + nitrite, total Kjedahl nitrogen, orthophosphate, total phosphorus, chlorophyll-*a*, total depth, and Secchi disk depth.

MONITORING REQUIREMENTS

24. Quality assurance and quality control for all monitoring requirements under this Order shall be achieved by compliance with the Quality Assurance Project Plan under the 2009 Monitoring Plan.

25. FPL shall timely apply for all regulatory approvals necessary for compliance with the monitoring requirements in this Order.

26. FPL shall continue to implement the monitoring program for the CCS, the 2009 Monitoring Plan, until such time as a monitoring plan is enacted pursuant to Section 403.087, F.S.

27. In addition to the monitoring requirements contained in the 2009 Monitoring Plan, FPL shall, within 90 days of the effective date of this Order, request or apply for regulatory approval to:

a. Obtain monitoring data from the USGS for the following wells for inclusion in the monitoring database: G-3946-S, G-3946-D, G-3900, G-3976, G-3966, and G-3699.

b. Install and monitor, consistent with the parameters and frequency set forth in the 2009 Monitoring Plan, a new 3 well cluster at G-3164. Construction shall commence within 180 days of FPL's receipt of all necessary regulatory approvals for the installation of the wells.

c. Replace and monitor, consistent with the parameters and frequency set forth in the 2009 Monitoring Plan well TPGW-8S. Construction shall commence within 180 days of FPL's receipt of all regulatory approvals necessary for compliance with this requirement.

d. Install and monitor, consistent with the parameters and frequency set forth in the 2009 Monitoring Plan a new deep well (to be designated as TPGW-20) located at the City of Homestead baseball complex, east of Kingman Road (SW 152nd Ave.) near the western parking area. Construction shall commence within 180 days of FPL's receipt of all regulatory approvals necessary for compliance with this requirement. The deep well will have a screened interval open to the deep high flow interval identified in the same manner as those described in the 2009 Monitoring Plan.

28. FPL shall expand the 2009 Monitoring Plan database to include all additional water monitoring data related to this Order required by all other governmental agencies and entities, including but not limited to the SFWMD, Nuclear Regulatory Commission, Miami-Dade County and the Florida Department of Health, as well as all monitoring data that is required in this Order.

29. In addition to the other monitoring requirements in this Order and for purposes of monitoring progress toward achievement of the hypersaline plume retraction, including determining whether the westward migration of the hypersaline plume has been halted and determining the rate of decline of saline levels in the CCS surface waters over time, the following monitoring requirements shall be met:

a. FPL shall conduct and report to the Department a baseline CSEM survey of the hypersaline plume after freshening activities are in operation but before the complete recovery well system begins operation. This will be the "Baseline Survey."

b. FPL shall conduct a CSEM survey within 30 days after the first year of recovery well operations and report the results to the Department.

c. FPL shall conduct a CSEM survey within 30 days after the second year of recovery well operations and report the results to the Department. This survey shall be the second CSEM survey.

d. FPL shall conduct a CSEM survey within 30 days after the third year of recovery well operations and report the results to the Department. This survey shall be the third CSEM survey.

e. FPL shall conduct and report to the Department subsequent CSEM surveys of the hypersaline plume 2 years after the third CSEM survey and every 2 years thereafter.

f. FPL shall monitor average weekly mass removal of salt as represented by total dissolved solids ("TDS"), by monitoring flow rate and weekly average TDS of the full extraction system, beginning at the time of commencement of the hypersaline plume remediation project operation.

g. FPL shall monitor average weekly chloride concentration of extracted water for the full extraction system, beginning at the time of commencement of the hypersaline plume remediation project operation.

h. FPL shall monitor average daily volume of hypersaline water extraction for the full extraction system, from beginning at the time of commencement of the Plume Extraction operation.

i. FPL shall maintain records of the operation of each extraction well (pump operation parameters such as: pump status, RPM, flow rate; water quality parameters such as salinity and TDS) and make such records available for review by the Department upon request, with reasonable notice.

j. FPL shall, when monitoring the salinity levels in the CCS, utilize all available monitoring resources in the CCS to obtain the average annual salinity rate. Specific monitoring points may not be excluded from the calculation unless such exclusion is allowed by the Department based upon a scientific reason. For the purposes

of determining average annual salinities for the CCS, FPL shall use qualified hourly data (pursuant to the approved 2009 Monitoring Plan QAPP) from each of the CCS monitoring sites TPSWCCS-1, 2, 3, 4, 5, 6, and 7 collected beginning at 00:00 through 23:59 each day. The qualified hourly data for the day will be summed and divided by the number of qualified hourly values for the station that day. Stations with fewer than 12 qualified hourly data values in a given day shall not be used in the calculation of the CCS daily average. The daily averages for all qualified stations (up to seven per day) for a given day will be summed and divided by the number of qualified stations for that day to produce a qualified CCS daily average salinity value. The average annual salinity is calculated by summing the qualified CCS daily average salinity values from June 1st through May 31st and dividing the value by the number of days in the year.

k. FPL shall monitor TPBBSW7T consistent with the parameters and frequency in the 2009 Monitoring Plan.

30. FPL will take reasonable actions to select appropriate laboratories with sufficient capacity to avoid delay in receiving results due to backlogs. If such delay occurs, FPL will make reasonable efforts to resolve those delays.

REPORTING REQUIREMENTS

31. The Annual Monitoring Report required by the 2009 Monitoring Plan shall be expanded to include:

a. All additional water monitoring data required under this Order.

b. All additional water monitoring data related to this Order required by all other governmental agencies or entities, including but not limited to the SFWMD, Nuclear Regulatory Commission, Miami-Dade County, and the Florida Department of Health, as well as all monitoring data that is required in this Order.

c. A reporting of the average annual salinity of the CCS waters.

32. FPL shall provide a report to the Department at the conclusion of the year-long control elevation project described in paragraph 17 of the Miami-Dade Consent Agreement detailing the results of the year-long raise in control elevations in the Everglades Mitigation Bank.

33. FPL shall provide the Department a copy of all reports/summaries/reviews required under any other agreements with any other agency, such as the reports/ summaries/ reviews required by the Miami-Dade Consent Agreement.

NOTICES

34. FPL shall allow all authorized representatives of the Department access to the Facility at reasonable times for the purpose of determining compliance with the terms of this Order and the rules and statutes administered by the Department.

35. This Order supersedes all the requirements of the Administrative Order related to the CCS at Turkey Point. Upon execution of this Order, the DEP Administrative Order (OGC No. 14-0741) is hereby rescinded.

36. If any event, including administrative or judicial challenges by third parties unaffiliated with FPL, occurs which causes delay or the reasonable likelihood of delay in complying with the requirements of this Order, FPL shall have the burden of proving the delay was or will be caused by circumstances beyond the reasonable control of FPL and could not have been or cannot be overcome by FPL's due diligence. Neither economic circumstances nor the failure of a contractor, subcontractor, materialman, or other agent (collectively referred to as "contractor") to whom responsibility for performance is delegated to meet contractually imposed deadlines shall be considered circumstances beyond the control of FPL (unless the cause of the contractor's late performance was also beyond the contractor's control). Failure of regulatory agencies to issue required permits consistent with this Order shall be considered a circumstance beyond the control of FPL if FPL acted with due diligence in the permit application process. Upon occurrence of an event causing delay, or upon becoming aware of a potential for delay, FPL shall notify the Department within 2 working days and shall, within seven calendar days notify the Department in writing of (a) the anticipated length and cause of the delay, (b) the measures taken or to be taken to prevent or minimize the delay, and (c) the timetable by which FPL intends to implement these measures. If the parties can agree that the delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of FPL, the time for performance hereunder shall be extended. The agreement to extend compliance must identify the provision or provisions extended, the new compliance date or dates, and the additional measures FPL must take to avoid or

minimize the delay, if any. Failure of FPL to comply with the notice requirements of this paragraph in a timely manner constitutes a waiver of FPL's right to request an extension of time for compliance for those circumstances.

37. The Department, for and in consideration of the complete and timely performance by FPL of all the obligations agreed to in this Order, hereby conditionally waives its right to seek judicial imposition of damages, civil penalties, or injunctive relief for the violations described in the Notice of Violation and above up to the date of the filing of this Order. This waiver is conditioned upon FPL's complete compliance with all of the terms of this Order.

38. This Order is a settlement of the Department's civil and administrative authority arising under Florida law to resolve the matters addressed herein. This Order is not a settlement of any criminal liabilities which may arise under Florida law, nor is it a settlement of any violation which may be prosecuted criminally or civilly under federal law. Entry of this Order does not relieve FPL of the need to comply with applicable federal, state, or local laws, rules, or ordinances.

39. The Department hereby expressly reserves the right to initiate appropriate legal action to address any violations of statutes or rules administered by the Department that are not specifically resolved by this Order.

40. FPL is fully aware that a violation of the terms of this Order may subject FPL to judicial imposition of damages, civil penalties up to $10,000.00 per day per violation, and criminal penalties.

41. FPL acknowledges and waives its right to an administrative hearing pursuant to sections 120.569 and 120.57, F.S., on the terms of this Order. FPL also acknowledges and waives its right to appeal the terms of this Order pursuant to section 120.68, F.S.

42. Electronic signatures or other versions of the parties' signatures, such as .pdf or facsimile, shall be valid and have the same force and effect as originals. No modifications of the terms of this Order will be effective until reduced to writing, executed by both FPL and the Department, and filed with the clerk of the Department.

43. The terms and conditions set forth in this Order may be enforced in a court of competent jurisdiction pursuant to sections 120.69 and 403.121, F.S. Failure to comply with the terms of this Order constitutes a violation of section 403.161(l)(b), F.S.

44. This Order is a final order of the Department pursuant to section 120.52(7), F.S., and it is final and effective on the date filed with the Clerk of the Department unless a Petition for Administrative Hearing is filed in accordance with Chapter 120, F.S.

45. When FPL demonstrates to the Department that it has fulfilled the requirements of this Order, the Department shall notify FPL in writing that all requirements of this Order are terminated except for the requirement to maintain the average annual salinity of the CCS at or below 34 PSU until an average annual salinity of the CCS is designated in a Department permit issued subsequent to the effective date of this Order.

46. Upon the timely filing of a petition, this Order will not be effective until further order of the Department.

47. FPL shall publish the following notice in a newspaper of daily circulation in Miami-Dade County, Florida. The notice shall be published one time only within 30 days of the effective date of the Order. FPL shall provide a certified copy of the published notice to the Department within 10 days of publication.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF CONSENT ORDER

The Department of Environmental Protection ("Department") gives notice of agency action of entering into a Consent Order with FPL pursuant to section 120.57(4), F.S. The Consent Order addresses the westward migration of hypersaline water from the Turkey Point Facility and potential releases to deep channels on the eastern and southern side of the Facility. The Consent Order is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at the Department of Environmental Protection Office of General Counsel, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000.

Persons who are not parties to this Consent Order, but whose substantial interests are affected by it, have a right to petition for an administrative hearing under sections 120.569 and 120.57, F.S. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition concerning this Consent Order

means that the Department's final action may be different from the position it has taken in the Consent Order.

The petition for administrative hearing must contain all of the following information:

a) The OGC Number assigned to this Consent Order;

b) The name, address, and telephone number of each petitioner; the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding;

c) An explanation of how the petitioner's substantial interests will be affected by the Consent Order;

d) A statement of when and how the petitioner received notice of the Consent Order;

e) Either a statement of all material facts disputed by the petitioner or a statement that the petitioner does not dispute any material facts;

f) A statement of the specific facts the petitioner contends warrant reversal or modification of the Consent Order;

g) A statement of the rules or statutes the petitioner contends require reversal or modification of the Consent Order; and

h) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the Department to take with respect to the Consent Order.

The petition must be filed (received) at the Department's Office of General Counsel, 3900 Commonwealth Boulevard, MS# 35, Tallahassee, Florida 32399-3000 within 21 days of receipt of this notice. A copy of the petition must also be mailed at the time of filing Division of Water Resource Management, Industrial Wastewater Program at 2600 Blair Stone Road, Mail Station 3545, Tallahassee, Florida 32399-2400. Failure to file a petition within the 21-day period constitutes a person's waiver of the right to request an administrative hearing and to participate as a party to this proceeding under sections 120.569 and 120.57, F.S. Before the deadline for filing a petition, a person whose substantial interests are affected by this Consent Order may choose to pursue mediation as an alternative remedy under section 120.573, F.S. Choosing mediation will not adversely affect such person's right to request an administrative hearing if mediation does not result in a settlement. Additional information about mediation is provided in section 120.573, F.S. and Rule 62- 110.106(12), Florida Administrative Code.

FOR THE RESPONDENT:

Randall R. LaBauve
Vice-President, Environmental Services
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

DONE AND ORDERED this 20th day of June, 2016, in Tallahassee, Florda.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

John A. Coates, P.E.
Director, Division of Water Resource Management

Filed, on this date, pursuant to section 120.52, F.S., with the designated Department Clerk, receipt of which is hereby acknowledged.

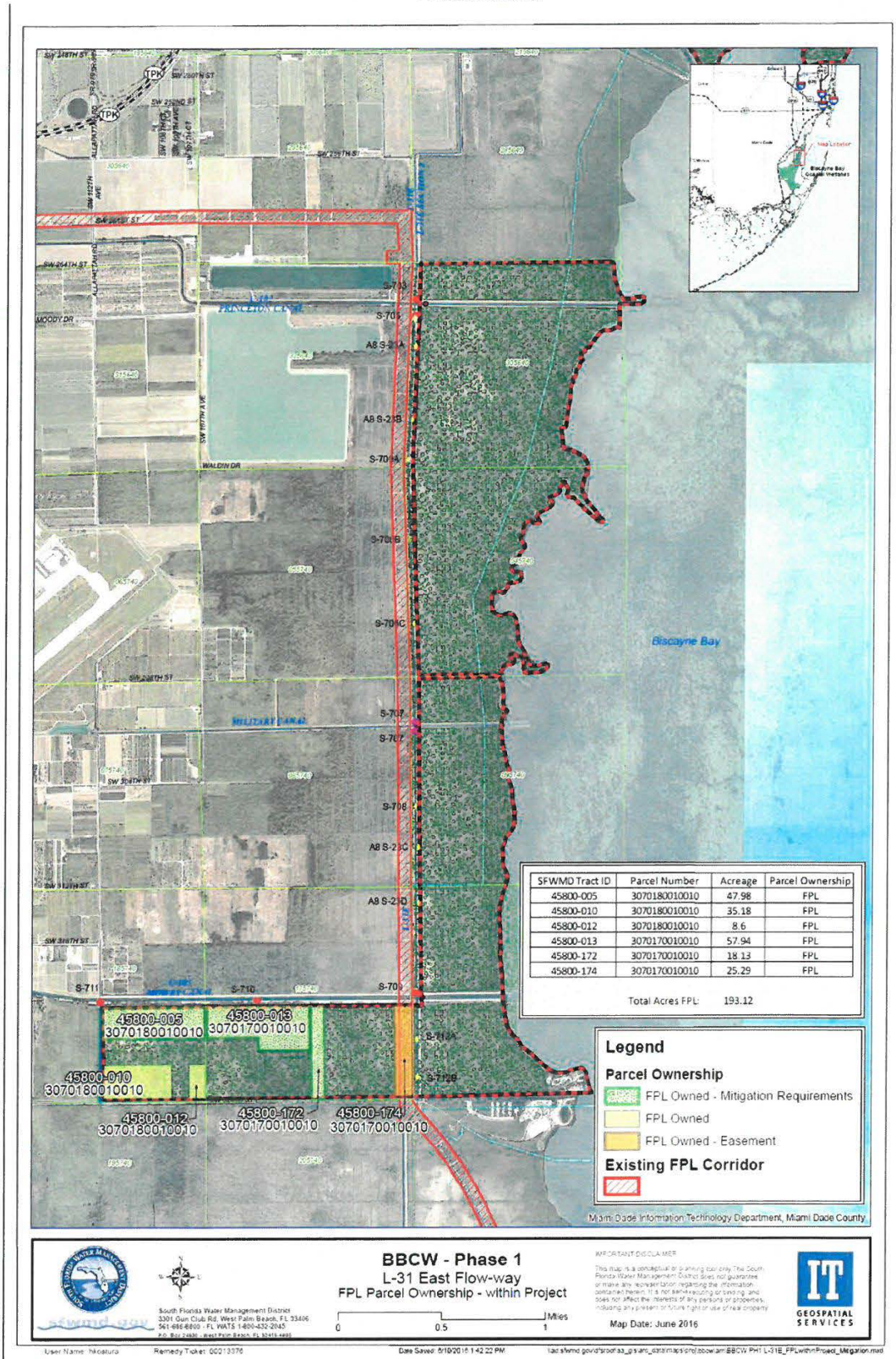
Clerk

Date 6/20/2016

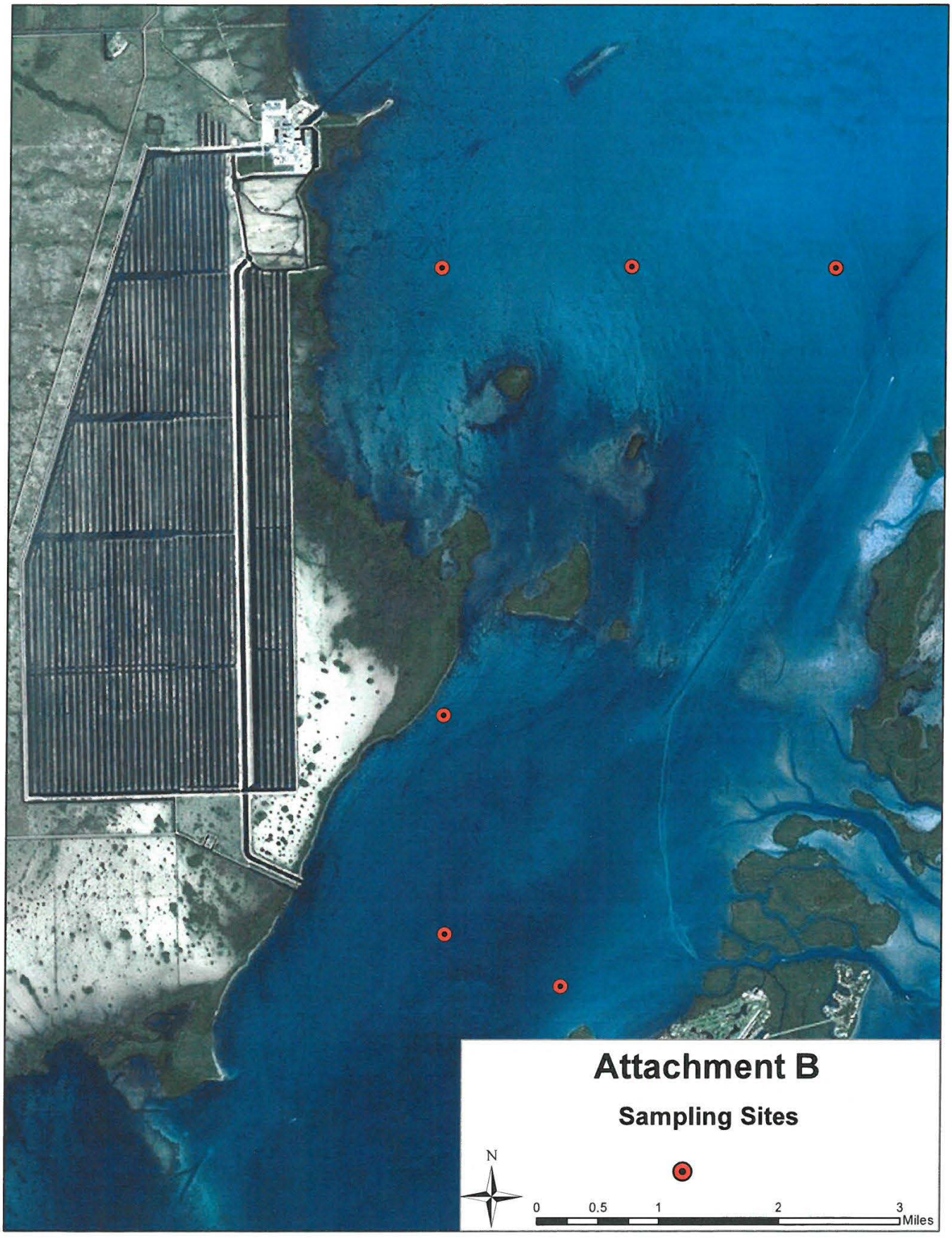
Copies furnished to:

Lea Crandall, Agency Clerk
Mail Station 35

Attachment A



SFWMD Tract ID	Parcel Number	Acreage	Parcel Ownership
45800-005	3070180010010	47.98	FPL
45800-010	3070180010010	35.18	FPL
45800-012	3070180010010	8.6	FPL
45800-013	3070170010010	57.94	FPL
45800-172	3070170010010	18.13	FPL
45800-174	3070170010010	25.29	FPL
Total Acres FPL:		193.12	


Attachment B
Sampling Sites
N
0
0.5
1
2
3
Miles

MIAMI-DADE COUNTY
Carlos A. Gimenez, Mayor

Department of Regulatory and Economic Resources
Environmental Resources Management
701 NW 1st Court, 6th Floor
Miami, Florida 33136-3912
T 305-372-6902 F 305-372-6630
miamidade.gov

August 15, 2016

Randall R. LaBauve, Vice President
Environmental Services
NextEra Energy, Inc.
700 Universe Blvd.
Juno Beach, Florida 33408

Certified Mail No. 7009 0080 0000 1050 8141
Return Receipt Requested

Re: Consent Agreement Addendum for the FPL Turkey Point power plant facility located at, near or in the vicinity of 9700 SW 344 Street, Unincorporated, Miami-Dade County, Florida.

Dear Mr. LaBauve:

Enclosed you will find an original of the above-referenced Consent Agreement Addendum which was executed today, August 15, 2016. Be advised that the date of execution initiates specific time periods with which FPL must comply as described in the Addendum.

If you have any questions concerning the above, please contact me at 305-372-6514 or email brownb@miamidade.gov. Thank you for your assistance in this matter.

Sincerely,

Barbara Brown

Barbara Brown
Special Projects Administrator
Regulatory Services

Enclosure

ec: Abbie Schwaderer-Raurell – CAO

Delivering Excellence Every Day

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 10
PARTY: MWS-6
DESCRIPTION: 2016 Consent Agreement Addendum

ADDENDUM 1 TO THE OCTOBER 7, 2015 CONSENT AGREEMENT
BETWEEN
MIAMI-DADE COUNTY DEPARTMENT OF REGULATORY AND ECONOMIC RESOURCES, DIVISION OF ENVIRONMENTAL RESOURCES MANAGEMENT
AND
FLORIDA POWER & LIGHT COMPANY

This Consent Agreement Addendum 1, entered into by and between Miami-Dade County Department of Regulatory and Economic Resources, Division of Environmental Resources Management (hereinafter referred to as "DERM"), and Florida Power & Light Company, (hereinafter referred to as "Respondent"), pursuant to Section 24-7(15)(c) of Chapter 24 of the Code of Miami-Dade County, shall serve to amend the October 7, 2015 Consent Agreement (Attachment 1) executed for the Turkey Point power plant facility and Cooling Canal System (CCS) located at, near or in the vicinity of 9700 SW 344 Street, Unincorporated, Miami-Dade County, Florida (DERM IW-3, IW-16, IW5-6229, DWO-10, CLI-2014-0312, HWR-851).

Subsequent to the Consent Agreement executed on October 7, 2015, a review of sampling data submitted by FPL and water quality sampling conducted by DERM revealed levels of ammonia as N exceeding the water quality standards set forth in Section 24-42(4) and clean-up target levels in Section 24-44(2)(f)(v)1, which constitutes water pollution as defined in Section 24-5 of the Code of Miami-Dade County. These results include ammonia as N in samples collected from surface water monitoring stations tidally connected to Biscayne Bay including, but not limited to, TPBBSW-7 and TPBBSW-8. This Consent Agreement requires FPL to take action to address the County's alleged violations of water quality standards and cleanup target levels relating to the exceedance of ammonia.

DERM and the Respondent agree to add Paragraph 34 to the October 7, 2015 Consent Agreement to address the referenced ammonia violations as follows:

34. Addendum 1.

    a. Within thirty (30) days of the execution of Addendum 1 of this Consent Agreement, the Respondent shall submit a Site Assessment Plan to DERM for review and approval which shall allow for the identification of the source(s) of the ammonia exceedances and the delineation of the vertical and horizontal extent of the subject ammonia exceedances in surface water. Said plan shall be adequate to address the ammonia exceedances to the surface waters surrounding the facility, including but not limited to, waters tidally connected to Biscayne Bay.

    b. Within sixty (60) days of DERM's approval of the Site Assessment Plan, the Respondent shall implement said plan and submit to DERM a Site Assessment Report for review and approval or approval with modifications which shall address the requirements of Item (a) above. The SAR shall include copies of the laboratory analytical reports, sampling logs, chain of custody forms and other information in accordance with the DERM approved Site Assessment Plan. All data submitted shall be in final form and no estimates or preliminary data will be accepted. All appropriate QA/QC documentation shall be submitted with the analytical results. In addition, all testing results submitted to DERM in response to this Addendum may be listed using the data form attached (Attachment 2).

c. Within ninety (90) days of approval of the Site Assessment Report, the Respondent shall submit to DERM for review and approval a Corrective Action Plan (CAP) prepared by a State of Florida registered professional engineer which, shall include, but not be limited to, the following:

   i. Design of an environmental restoration plan to correct the exceedences of ammonia standards and criteria,

   ii. Details of proposed process modifications or changes in operational systems to manage and control the source(s) of ammonia to prevent future violations of the provisions of Chapter 24 at the subject facility,

   iii. Physical, structural, or hydraulic modifications in the area of the CCS and adjacent surface waters to eliminate the contributions of CCS waters to the surface waters of Miami-Dade County, and

   iv. A time table for implementation and completion of the Corrective Action Plan.

d. Upon approval of the CAP, the Respondent shall implement said CAP in accordance with the approved timetable in order to cease discharges from the Turkey Point facility that cause or contribute to ammonia exceedances in violation of County water quality standards, cleanup target levels or which cause water pollution.

e. Within thirty (30) days of the execution of Addendum 1 to this Consent Agreement, the Respondent shall pay DERM administrative costs in the amount of five thousand dollars ($5,000.00). The payment shall be made payable to Miami-Dade County and sent to DERM, 701 NW 1st Court, 6th Floor, Miami, Florida 33136, Attention: Barbara Brown.

All other provisions of the October 7, 2015 Consent Agreement shall remain unchanged and in full force and effect for the duration of that Agreement.

This Consent Agreement Addendum 1 and the provisions herein shall become effective upon execution by the Director of DERM or the Director's designee.

[REMAINDER OF PAGE INTENTIONALLY BLANK; SIGNATURES APPEAR ON FOLLOWING PAGE]

8/12/2016
Date

Signature

Randall R. LaBauve
Print Name and Title

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Respondent

Notary Public State of Florida
Fannie Strickland
My Commission FF 992597
Expires 05/15/2020

Before me, the undersigned authority, personally appeared Randy R. LaBauve who after being duly sworn, deposes and says that he has read the foregoing.

Subscribed and sworn to before me this 12th day of August, 2016 by Randy R. LaBauve.
(Name of affiant)

Personally Known ✓ or Produced Identification ____.
(Check One)

Type of Identification Produced: _____

Notary Public

DO NOT WRITE BELOW THIS LINE OFFICE USE ONLY

8-15-2016
Date

Lee N. Hefty, Director
Environmental Resources Management

Barbara Brown
Witness

Witness

MIAMI-DADE COUNTY, through its DEPARTMENT OF REGULATORY AND ECONOMIC RESOURCES, DIVISION OF ENVIRONMENTAL RESOURCES MANAGEMENT,

Complainant,

v.

FLORIDA POWER & LIGHT COMPANY,

Respondent.
_____/

CONSENT AGREEMENT

This Consent Agreement, entered into by and between the Complainant, MIAMI-DADE COUNTY, through its DEPARTMENT OF REGULATORY AND ECONOMIC RESOURCES, DIVISION OF ENVIRONMENTAL RESOURCES MANAGEMENT ("DERM"), and the Respondent FLORIDA POWER & LIGHT COMPANY ("FPL"), pursuant to Section 24-7(15)(c) of the Code of Miami-Dade County, shall serve to redress alleged violations of Chapter 24 of the Code of Miami-Dade County located near, surrounding, or in the vicinity of the Cooling Canal System located at Turkey Point on FPL's property, as further described herein, in Miami-Dade County, Florida.

DERM and FPL enter into the following Consent Agreement:

FINDINGS OF FACT

1. DERM is a division of Miami-Dade County, a political subdivision of the State of Florida, which is empowered to control and prohibit pollution and protect the environment within Miami-Dade County pursuant to Article VIII, Section 6 of the Florida Constitution, the Miami-Dade County Home Rule Charter and Section 403.182 of the Florida Statutes.

2. Florida Power & Light Company ("FPL") is the owner and operator of the Turkey Point Power Plant, and FPL is the owner and operator of approximately a 5,900-acre network of unlined canals (the "Cooling Canal System" or "CCS") on the FPL property described in the map in Exhibit A (the "Property").

3. In 1971, FPL signed a Consent Decree with the U.S. Department of Justice that required the construction, after permitting, of a closed-loop cooling configuration, with no discharge to surface waters.

4. The Florida Department of Pollution Control (later to become the Florida Department of Environmental Protection), in 1971, issued Construction Permit No. IC-1286 for the CCS. In 1972, Dade County issued Zoning Use Permit No. W-49833 for the excavation of the proposed Alternate Cooling Water Return Canal. FPL represents that in 1973, the construction of the CCS was completed; and the CCS was closed from the surface waters of both Biscayne Bay and Card Sound, becoming a closed-loop system.

5. An approximate 18 foot deep interceptor ditch located along the west side of the CCS was designed and constructed to create a hydraulic barrier to keep water in the CCS from migrating inland or westward.

6. In 1972, FPL entered into an agreement with the Central and Southern Florida Flood Control District (later to become the South Florida Water Management District or "District") addressing the operations and impacts of the CCS. The agreement has been updated several times, with the most recent version being the Fifth Supplemental Agreement between the District and FPL entered into on October 16, 2009 ("Fifth Supplemental Agreement") which included an extensive monitoring program for the CCS, entitled the Turkey Point Plant Groundwater, Surface Water and Ecological Monitoring Plan ("2009 Monitoring Plan"), incorporated as Exhibit A of the Fifth Supplemental Agreement.

7. In a letter dated April 16, 2013, the District notified FPL of their determination that saline water from the CCS has moved westward of the L-31E Canal in excess of those amounts that would have occurred without the existence of the CCS, and pursuant to the provisions of the Fifth Supplemental Agreement, initiated consultation with FPL for the mitigation, abatement or remediation of the saline water movement.

8. DERM issued a Notice of Violation dated October 2, 2015 (the "NOV") to FPL, alleging violations of Chapter 24 of the Code of Miami-Dade County, for alleged violations of County water quality standards and criteria in groundwater attributable to FPL's actions, and specifically for groundwaters outside the boundaries of FPL's Cooling Canal System and beyond the boundaries of the Property.

9. The phrase "hypersaline water" as used herein is defined as water that exceeds 19,000 mg/L chlorides.

10. DERM maintains there is hypersaline water attributable to FPL's actions in the groundwaters outside the boundaries of the Property, which exceeds County water quality standards and criteria. FPL acknowledges the presence of hypersaline water in certain areas outside the boundaries of the Property. For waters that do not reach the level of hypersalinity, DERM and FPL do not agree on the applicable "background" standards for chlorides.

11. In 2013 and 2014, FPL experienced water quality issues within the CCS, including increases in temperature and salinity, and FPL sought approvals from various regulatory agencies for actions to improve the water quality within the CCS.

12. DEP issued an Administrative Order, No. 14-0741, on December 23, 2014, requiring FPL to, among other things, reduce and maintain the annual average salinity of the CCS at a practical salinity of 34, and that Administrative Order is currently the subject of an Administrative Hearing.

13. Both DERM and FPL agree and acknowledge that it would be beneficial to improve the water quality within the Cooling Canal System itself, and FPL has already undertaken some efforts to improve the CCS water quality.

14. This Consent Agreement requires FPL to take action to address the County's alleged violations of County water quality standards and criteria in groundwaters outside the CCS as described in the NOV. As part of these actions, this Consent Agreement also requires FPL to take into account its efforts to improve CCS water quality and the potential and actual impacts of such actions on water resources outside the CCS, to not cause or contribute to (i) the exacerbation of alleged violations of County water quality standards or criteria or (ii) future violations of County water quality standards or criteria in the groundwaters or surface waters outside the CCS.

15. FPL hereby agrees to the terms of this Consent Agreement without admitting the allegations made by the above-mentioned NOV.

16. In an effort to expeditiously resolve this matter and to ensure compliance with Chapter 24 of the Code of Miami-Dade County, and to avoid time consuming and costly litigation, the parties hereto agree to the following, and it is ORDERED:

REQUIREMENTS

17. FPL shall undertake the following activities to specifically address water quality impacts associated with the CCS, as alleged in the NOV. The objective of this Consent Agreement will be for FPL to demonstrate a statistically valid reduction in the salt mass and volumetric extent of hypersaline water (as represented by chloride concentrations above 19,000 mg/L) in groundwater west and north of FPL's property without creating adverse environmental impacts. A further objective of this Consent Agreement is to reduce the rate of, and, as an ultimate goal, arrest migration of hypersaline groundwater. Recognizing other factors beyond FPL's control may influence movement of groundwater in the surficial aquifer, FPL shall reasonably take into account such factors when developing and implementing remedial actions to minimize the timeframe for achieving compliance with this Consent Agreement.

a. Abatement.

i. DERM acknowledges that FPL is planning to undertake the following:

1. pursue permitting, construction and operation of up to six Upper Floridan Aquifer System wells in accordance with the Site Certification Modification that is the subject of DOAH Case No. 15-1559EPP.

2. continue the use of the existing marine wells (SW-1, SW-2, and PW-1) as a short term resource to lower and maintain salinities. FPL shall work to avoid the use of the marine wells, except under extraordinary circumstances.

3. continue operation of the authorized L-31E canal pumps as a short term resource only, in accordance with the terms and conditions of the applicable approvals. FPL acknowledges that the use of water from the L-31E canal is intended only as a short term resource to lower CCS salinity. FPL anticipates the need for this resource for the next two years to reduce salinity as it transitions into the long term resources that are intended to maintain the lower salinity in the CCS. FPL acknowledges that additional regulatory

approvals will be required for continuation of this activity beyond the expiration of the existing approvals.

ii. FPL shall evaluate alternative water sources to offset the CCS water deficit and reduce chloride concentration in the CCS, and as a means of abating the westward movement of CCS groundwater. FPL will consider the practicality and appropriateness of using reclaimed wastewater from the Miami-Dade County South District Waste Water Treatment Plant as an alternative water source. FPL will provide DERM a summary of its Alternative Water Supply plan within 180 days of executing the Consent Agreement. FPL recognizes the importance and potential for reuse water, and FPL will make good faith efforts to implement the use of reuse water where practicable.

iii. FPL shall also conduct a review of the Interceptor Ditch operations to determine if current design and/or operations can be practicably modified to improve its function recognizing the current status of the CCS and surrounding wetlands. FPL will provide a summary of its Interceptor Ditch Review within 180 days of executing the Consent Agreement.

iv. The alternative water sources and any modifications to Interceptor Ditch design or operation shall be authorized through the appropriate regulatory processes and shall be demonstrated to not create adverse impacts to surface waters, groundwater, wetland or other environmental resources consistent with the Fifth Supplemental Agreement.

b. Remediation. FPL shall develop and implement the following actions to intercept, capture, contain, and retract hypersaline groundwater (groundwater with a chloride concentration of greater than 19,000 mg/L) to the Property boundary to achieve the objectives of this Consent Agreement.

i. Phase I. FPL shall design, permit, and construct a Biscayne Aquifer Recovery Well System (RWS) based on the results of a variable density dependent groundwater model which shall be sufficient to support the design of the RWS to intercept, capture, and contain the hypersaline plume; support authorization through the appropriate regulatory processes; and demonstrate that it will not create adverse

impacts to groundwater, wetland (hydroperiod or water-stage), or other environmental resources. Final operation and design will be informed by an Aquifer Performance Test (APT). FPL shall provide its design and supporting information for the Recovery Well System and associated monitoring wells for DERM review and approval within 180 days of executing the Consent Agreement. FPL shall proceed with implementation within one year of executing the Consent Agreement, subject to regulatory timelines not in FPL's control. The initial design will be based on up to 12 MGD disposal capacity recognizing existing on-site capability. Efficacy of this design constraint will be reviewed in Phases 2, 3, and 4.

ii. Phase 2. FPL shall operate the RWS in accordance with all local, state, and federal regulatory requirements, collect data as required by the monitoring program, and employ the data to inform and reduce the uncertainty of the groundwater model. Status and efficacy of the system operation in meeting the objectives of this Consent Agreement and results of continued groundwater model refinement will be provided in the annual reports required in Paragraph 17d.

iii. Phase 3. After five years, FPL shall evaluate the effectiveness of the RWS in achieving the goal to intercept, capture, contain, and ultimately retract the hypersaline groundwater plume. This evaluation shall include estimated milestones and be based on the results of the monitoring data and refined groundwater/surfacewater model, which will be submitted to DERM. If the analysis indicates that the RWS is not anticipated to achieve the goal to intercept, capture, contain, and ultimately retract the hypersaline groundwater plume, FPL shall make recommendations for modifications to the project components and/or designs to ensure the ability of the system to achieve the objectives of the Consent Agreement. The evaluation and any proposed revisions shall be submitted to DERM for review and approval.

iv. Phase 4. After ten years, FPL shall review the results of the activities and progress to achieve the objectives of this Consent Agreement, and this evaluation shall be submitted to DERM. If monitoring demonstrates that the activities are not achieving the objectives of this Consent Agreement, FPL shall revise the project components and/or designs to ensure the ability of the system to achieve the objectives of this

Consent Agreement. The proposed revisions shall be submitted to DERM for review and approval.

c. Regional Hydrologic Improvement Projects. In addition, FPL agrees to undertake the following:

i. Raise control elevations in the Everglades Mitigation Bank. Within 30 days of the effective date of this Consent Agreement, FPL shall raise the control elevations of the FPL Everglades Mitigation Bank ("EMB") culvert weirs to no lower than 0.2 feet lower than the 2.4 foot trigger of the S-20 structure and shall maintain this elevation. After the first year of operation, FPL shall evaluate the change in control elevation, in regards to improvements in salinity, water quality, and lift in the area, and if FPL determines that the change in control elevations is not effective, or that FPL is negatively impacted in receiving mitigation credits as a result of this action, FPL will consult with DERM and propose potential alternatives.

ii. Fill portions of the Model Lands North Canal within the Everglades Mitigation Bank. Within 30 days of the effective date of the Consent Agreement, FPL shall seek all necessary regulatory approvals to place excavated fill from the adjoining roadway into the Model Lands North Canal within FPL's Everglades Mitigation Bank. Upon issuance of such regulatory approvals, FPL shall, starting on the east end, fill the Model Lands North Canal. This Consent Agreement only requires FPL to fill to the extent the fill is available from the adjoining roadway permitted to be degraded.

iii. If the District determines that flowage easements are needed from FPL in order to increase the operational stages of the S-20 water control structure as planned and approved by CERP, FPL agrees to provide such flowage easements for FPL owned land within the Everglades Mitigation Bank, in favor of the District within six months of the determination.

iv. FPL acknowledges the benefit of hydrologic restoration projects contemplated by the Comprehensive Everglades Restoration Project ("CERP"), as well as other government entities, adjacent and to the west of the CCS in controlling movement of hypersaline and saline waters in the Biscayne Aquifer. FPL commits to working with

local, state and federal agencies to facilitate implementation of these projects to promote improved hydrologic conditions.

d. Monitoring and Reporting. FPL shall conduct monitoring to evaluate the progress made in achieving the objectives of this Consent Agreement. This includes actions that result from satisfying the abatement, remediation and hydrologic improvement components of this Consent Agreement. FPL shall initiate the monitoring and reporting requirements identified below within 30 days of executing the Consent Agreement. The monitoring shall include the following:

i. FPL shall facilitate DERM access to all data from continuous electronically monitored stations.

ii. FPL shall continue to provide monthly and quarterly reports substantially consistent with those required in M-D Class I permit CLI-2014-0312, beyond the expiration of the permit.

iii. FPL shall employ Continuous Surface Electromagnetic Mapping (CSEM) methods to assess the location and orientation of the hypersaline plume west and north of the CCS.

iv. FPL shall add three groundwater monitoring clusters (shallow, mid and deep) to monitor groundwater conditions in the model lands basin. The well clusters shall be similar in design and function to existing groundwater monitoring wells in the region as part of the CCS monitoring program, and shall be geographically located in consultation with DERM.

v. FPL shall submit annual reports providing an evaluation of progress in achieving the objectives of this Consent Agreement, status of implementing projects identified above, and the results of monitoring to determine the impacts of these activities. Recommendations for refinements to the activities will be included in the annual report. This may include deletions of monitoring that is demonstrated to no longer be needed, or additional monitoring that is warranted based on observations.

SAFETY PRECAUTIONS

18. FPL shall maintain the subject property during the pendency of this Consent Agreement in a manner which shall not pose a hazard or threat to the public at large or the environment and shall not cause a nuisance or sanitary nuisance as set forth in Chapter 24 of the Code of Miami-Dade County, Florida.

VIOLATION OF REQUIREMENTS

19. This Consent Agreement constitutes a lawful order of the DERM Director and is enforceable in a civil court of competent jurisdiction. Violation of any requirement of this Consent Agreement may result in enforcement action by DERM. Each violation of any of the terms and conditions of this Consent Agreement by FPL shall constitute a separate offense.

SETTLEMENT COSTS

20. FPL hereby certifies that it has the financial ability to comply with the terms and conditions herein and to comply with the payment of settlement costs specified in this Agreement.

21. DERM has determined that due to the administrative costs incurred by DERM for this matter, a settlement of $30,000.00 is appropriate. FPL shall, within sixty (60) days of the effective date of this Consent Agreement, submit to DERM a check in the amount of $30,000.00 for full settlement payment. The payment shall be made payable to Miami-Dade County and sent to the Division of Environmental Resources Management, c/o Barbara Brown, 701 NW 1st Court, 6th Floor, Miami, FL 33136-3912.

22. In the event that FPL fails to submit, modify, implement, obtain, provide, operate and/or complete those items listed in paragraph 17 herein, FPL shall pay DERM a civil penalty of one hundred dollars ($100.00) per day for each day of non-compliance and FPL may be subject to enforcement action in a court of competent jurisdiction for such failure pursuant to those provisions set forth in Chapter 24 of the Code of Miami-Dade County. Any such payments shall be made by FPL to DERM within ten days of receipt of written notification and shall be sent to the Division of Environmental Resources Management, 701 NW 1st Court, 6th Floor, Miami, FL 33136-3912.

GENERAL PROVISIONS

23. FPL shall allow any duly authorized representative of DERM, with reasonable notification, to enter and inspect the CCS, Floridan wells, extraction wells, or any other relevant facilities, at any reasonable time for the purpose of ascertaining the state of compliance with the terms and conditions of this Consent Agreement. DERM shall comply with the plant safety and security precautions. FPL shall provide and maintain a point of contact at the Turkey Point Power Plant to assist DERM in accessing the facilities to be inspected.

24. On a quarterly basis (January, April, July, and October), DERM may collect surface and/or groundwater samples at the discretion of DERM at various monitoring locations in accordance with monitoring referenced in Paragraph 17 above.

25. FPL and DERM agree to cooperate and use best efforts moving forward related to this Consent Agreement.

26. Disputes related to or arising out of this Consent Agreement shall be construed consistent with the laws of the State of Florida and the United States, as applicable, and shall be filed in the state or federal courts of the State of Florida, as appropriate. Proceedings shall take place exclusively in the Circuit Court for Miami-Dade County, Florida or the United States District Court for the Southern District of Florida.

27. In consideration of the complete and timely performance by FPL of the obligations contained in this Consent Agreement, DERM waives its rights to seek judicial imposition of damages or civil penalties for the matters alleged in Notice of Violation and Consent Agreement.

28. Where FPL cannot meet timetables or conditions due to circumstances beyond FPL's control, FPL shall provide written documentation to DERM which shall substantiate that the cause(s) for delay or non-compliance was not reasonably in FPL's control. DERM shall make a determination of the reasonableness of the delay for the purpose of continued enforcement pursuant to paragraph 22 of this Consent Agreement.

29. DERM expressly reserves the right to initiate appropriate legal action to prevent or prohibit future violations of applicable laws, regulations, and ordinances or the rules promulgated thereunder.

30. Entry of this Consent Agreement does not relieve FPL of the responsibility to comply with applicable federal, state or local laws, regulations, and ordinances.

31. FPL acknowledges that this Consent Agreement is within the jurisdiction of Miami-Dade County. Nothing in this Consent Agreement is intended to expand, nor shall this Consent Agreement be construed to expand, the regulatory authority or jurisdiction of Miami-Dade County.

32. This Consent Agreement shall neither be evidence of a prior violation of this Chapter nor shall it be deemed to impose any limitation upon any investigation or action by DERM in the enforcement of Chapter 24 of the Code of Miami-Dade County.

33. This Consent Agreement shall become effective upon the date of execution by the DERM Director, or the Director's designee.

October 6, 2015

Date

Eric E. Silagy
President & CEO
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Respondent

Before me, the undersigned authority, personally appeared Eric Silagy, who after being duly sworn, deposes and says that they have read and agreed to the foregoing.

Subscribe and sworn to before me this 6th day of October, 2015 by Eric Silagy (name of affiant).

Personally known ✓ or Produced Identification _____.
(Check one)

Type of Identification Produced: _____.

LISA GROVE
MY COMMISSION # FF 154741
EXPIRES: December 14, 2018
Bonded Thru Budget Notary Services

Lisa Grove
Notary Public Signature

Lisa Grove
Notary Public Printed Name

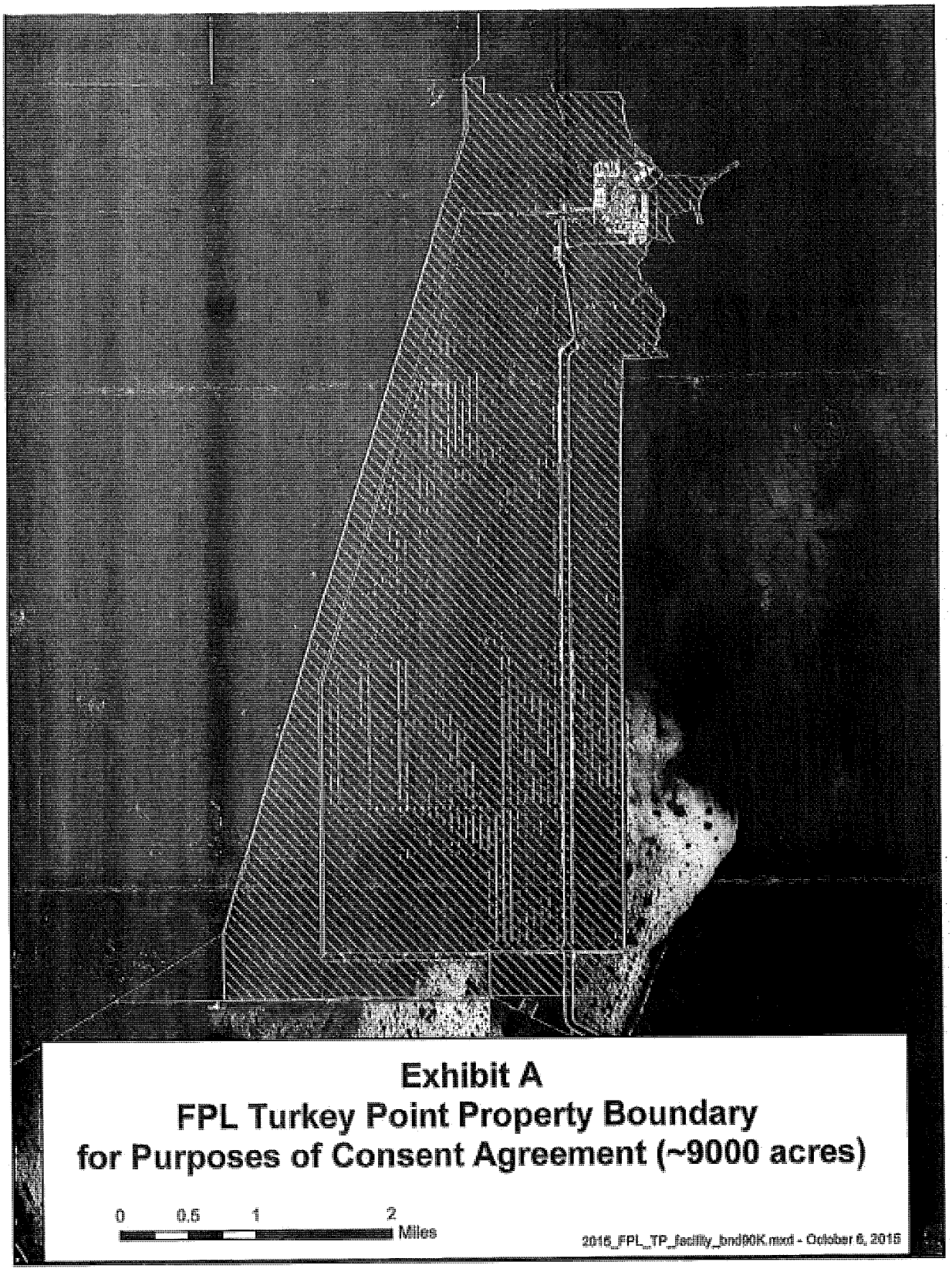
DO NOT WRITE BELOW THIS LINE – GOVERNMENT USE ONLY

OCT 7, 2015
Date

Lee N. Hefty, DERM Director
Miami-Dade County

Witness

Barbara Brown
Witness


Exhibit A
FPL Turkey Point Property Boundary
for Purposes of Consent Agreement (~9000 acres)
0
0.5
1
2
Miles
2016_FPL_TP_facility_bnd90K.mxd - October 6, 2016

FPL TURKEY POINT SAMPLING RESULTS

MONITORING LOCATION (SAMPLE ID)	COLLECTION DATE & TIME	SECONDS	FIELD TEMPERATURE (°C)	ANALYTICAL METHOD USED	CHLOROPHYLL a (mg/m^3)	CHLORIDE (mg/L)	SULFATE (mg/L)	NITROGEN, KJELDAHL (mg/L)	NITRATE NITRITE as N (mg/L)	PHOSPHORUS as P (mg/L)	ORTHO-PHOSPHATE as P, DISSOLVED (mg/L)	COPPER (mg/L)	SODIUM (mg/L)	FIELD pH	OXYGEN (mg/L)	SALINITY (PSU)	SPECIFIC CONDUCTANCE (umhos/cm)	TOTAL DISSOLVED SOLIDS	TURBIDITY (NTU)	AMMONIA as N, (TOTAL AMMONIA NH_3+NH_4) (mg/L)	AMMONIA, IONIZED NH_4 (mg/L)	AMMONIA, UNIONIZED NH_3 (mg/L)



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 11
PARTY: MWS-7
DESCRIPTION: July 2020 Plan Submitted to FDEP

July 30, 2020

Mr. John J. Truitt
Deputy Secretary of Regulatory Programs
Florida Department of Environmental Protection
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

RE: Consent Order OGC File No. 16-0241 P. 20.a. Supplemental Salinity Management Plan

Dear Mr. Truitt:

The 2016 Consent Order ("CO") between Florida Power & Light Company ("FPL") and the Florida Department of Environmental Protection ("Department") outlines three objectives: (1) cease discharges from the Cooling Canal System ("CCS") that impair the reasonable and beneficial use of the adjacent G-II groundwater to the west of the CCS; (2) prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards in the Bay; and (3) provide mitigation for impacts related to historic operation of the CCS. Since 2016, FPL has substantially accomplished the objectives of the CO and continues successful execution on all requirements within it. This letter serves to update the Department on FPL's successes under the CO and to provide a supplemental salinity management plan pursuant to condition 20.a that outlines additional measures, and timeframes, FPL will implement to achieve the salinity threshold.

Successes

Over the past year, FPL accomplished several milestones associated with the second and third objectives of the CO. Pursuant to objective two, we completed the Turtle Point and Barge Basin restoration project in May 2020. More than 200,000 cubic yards of clean beach quality sand was placed within the canals to restore the canal bathymetry and improve natural tidal circulation. In addition, more than 1,700 mangroves were planted in the newly created ~0.8-acre mangrove habitat within the Turtle Point canal. The mangrove habitat will provide additional foraging, breeding, and spawning habitat and improve the overall coastal ecosystem. Pursuant to objective three, FPL entered into an agreement with the South Florida Water Management District in April 2018 to convey to the District FPL property interests within the Biscayne Bay Coastal Wetlands Comprehensive Everglades Restoration Project footprint. In December 2019, several of those properties were conveyed to the District.

FPL has also accomplished a number of milestones associated with the CO's first objective. The CO includes a number of activities intended to accomplish this objective: freshening; eliminating the CCS contribution to the hypersaline plume; maintaining the average annual salinity of the CCS at or below 34 Practical Salinity Units ("PSU"); halting the westward migration of hypersaline water from the CCS; and reducing the westward extent of the hypersaline plume to the L-31E within 10 years.

To halt and retract the hypersaline groundwater west of the CCS, FPL constructed a recovery well system ("RWS") and began utilizing 10 wells in May 2018 to extract 15 MGD of hypersaline water. The RWS functions as a hydrological barrier that prevents the net movement of additional water from the CCS to locations in the

aquifer west of the CCS. The RWS also functions to remove hypersaline water that migrated west of the CCS prior to installation of the recovery wells. After one year of operation, Continuous Surface Electromagnetic Mapping ("CSEM") showed a 22% reduction in the total volume of the hypersaline groundwater west and north of the CCS. As a result of all of FPL's actions, including interim extraction, FPL has removed over 8.4 billion pounds of salt from the Biscayne Aquifer since 2016.

To freshen the CCS, FPL installed five artesian-flowing Upper Floridan Aquifer wells to provide up to 14 MGD of brackish water to the CCS. In recent months, FPL also received approval to utilize a portion of Turkey Point Units 1-5's existing process water allocation to provide up to an additional 7 MGD of brackish Floridan Aquifer water to aid in CCS salinity reduction. These freshening measures have been instrumental in moderating CCS salinity over the three-and-a-half year freshening timeframe. Results from the agency-approved water and salt budget modeling show that the freshening to date has been effective in reducing the salinity in the CCS by over 20 PSU from levels that would have occurred had freshening measures not been implemented.

Supplemental Salinity Management Plan & Timeframes

Although FPL's freshening actions have been effective in moderating CCS salinity, we expect the average annual salinity to be above 34 PSU by November 28, 2020, the CO's timeframe for achieving the salinity threshold. CCS salinity is influenced by many factors, including, but not limited to, rainfall, air temperatures, and CCS evaporation rates. The CO recognizes these factors and includes a process to supplement CCS salinity reduction measures to achieve the salinity threshold. Specifically, CO Paragraph 20.a. indicates if FPL does not reach an average annual salinity of 34 PSU by the end of the fourth freshening year (November 28, 2020) then FPL must submit a plan within 30 days (December 28, 2020) detailing additional measures, and a timeframe, that will be implemented to achieve the salinity threshold. Therefore, and in advance of the December deadline, we are providing factors that affected CCS salinity during the freshening period and additional measures, and timeframes, FPL is undertaking to achieve the 34 PSU threshold ("Supplemental Salinity Management Plan" or "Plan"). FPL believes this Plan will increase CCS resilience and provide the much-needed operational flexibility to address variable conditions like rainfall and air temperature to achieve 34 PSU.

The salinity management plan originally presented to the Department in 2013 included an estimated freshening volume of 14 MGD of brackish groundwater needed to offset annual average CCS evaporative losses. The water and salt budget model used to support the initial freshening estimate utilized the best data available at the time, collected between 2010-2012. FPL now has a data record that covers a longer time period (2010-2019) and represents a wider range of hydrologic conditions. CCS salinity responses have shown that offsetting evaporative losses is more beneficial on a monthly basis, rather than on an annual average basis as used in the original modeling. By providing sufficient freshening to prevent dry season CCS salinity increases, combined with wet season surpluses, the net annual salinity will decrease in accordance with the requirements of the CO.

FPL analyzed the longer data record and utilized the agency-approved water and salt budget model to determine the additional brackish water beyond current allocations needed to offset evaporative losses and meet the CO's 34 PSU salinity threshold. We plan to undertake a number of actions as part of this Supplemental Salinity Management Plan to achieve the threshold and increase CCS resiliency.

In the near-term, we are maximizing our existing infrastructure and water use allocations to increase freshening volumes within permitted limits. Natural artesian pressure is currently producing approximately 11 of the 14 MGD allocation. Well maintenance was performed on four wells between March 2019 and May 2019 to improve well performance. Between 70% and 79% of the original well capacity was obtained from the effort, but more production is needed to reach 14 MGD. Therefore, FPL plans to install pumps on the permitted wells to reach the full allocation and provide an additional 3 MGD for CCS freshening by the end of the year.

FPL also plans to request a site certification modification to increase our brackish water allocation by 16 MGD, bringing the total freshening capacity to 30 MGD. This would include a monthly max allocation of 34 MGD

to provide operational flexibility to offset monthly CCS evaporative losses. To inform the updated freshening volume needs, FPL evaluated the use of 30 MGD brackish water using the water and salt budget model. Absent a significant drought, the model indicates the 34 PSU annual average salinity threshold would be met by the end of the second year of freshening assuming similar hydrologic conditions to the dry conditions that occurred at the CCS in 2017 and 2018. Rainfall in South Florida is highly variable both seasonally and interannually. The previous nine-year record shows a wide range for rainfall year-to-year for any given month. In addition, review of nine years of monthly CCS rainfall and evaporation water budget data indicates evaporation exceeded rainfall by over 30 MGD 25% of the time in the period of record analyzed; therefore, the max month allocation of 34 MGD will allow for dynamic management of the allocation to offset the variation in monthly evaporative losses. The Plan considers natural variability and accordingly provides FPL operational flexibility to address changing conditions while improving CCS resiliency.

As part of the planning process, FPL examined whether the additional freshening would have any impact on seepage rates from the CCS. FPL used the agency-approved variable density flow and salt transport groundwater model for the calculations. The assessment determined that the increased freshening would result in a 0.1-foot stage increase in the CCS. However, as a result of the reduced fluid density of the 34 PSU CCS water, seepage rates to both the east and west will in fact be decreased compared with current conditions. The additional freshening will therefore have a positive impact on remediation of the hypersaline plume and will not hinder FPL's ability to meet its obligations under the CO to reduce the westward extent of the hypersaline plume to the L-31E within 10 years. The additional freshening will, as the modeling indicates, clearly help to remediate the hypersaline plume.

FPL is mindful of its water use and is using the lowest water quality source available (brackish water identified as an alternative water supply source by the South Florida Water Management District) for freshening, process, and cooling water purposes at Turkey Point. We are requesting the use of additional brackish water because we believe it is the best solution to manage salinity and will not negatively impact existing legal users. FPL will include a water conservation plan in our site certification modification that will adjust the amount of brackish water use once the 34 PSU threshold is achieved. FPL has also continued to build the foundation for a partnership with Miami-Dade County to treat up to 15 MGD of reclaimed water at Turkey Point for the Unit 5 cooling towers (see June 2020 Miami-Dade Board of County Commissioners Resolution No. R-579-20). This opportunity will help Miami-Dade County meet state reuse requirements while also replacing the brackish Floridan groundwater as a primary source for Unit 5 cooling purposes, reducing Unit 5 groundwater withdrawals. This will offset site-wide use of brackish water.

FPL is proud of our successes in implementing the Consent Order. As contemplated by the CO, we have used the over 4.5 million data points gathered annually to analyze the outcomes of our actions and make adjustments as necessary. We believe the supplemental actions we are undertaking and proposing will allow us to achieve our remaining targets under the CO, and we are proud of Turkey Point's safe delivery of greenhouse gas free power for almost fifty years.

FPL intends to submit the site certification modification application in the third quarter of 2020 and expects to complete permitting and implement the increased freshening allocation in the second quarter of 2021. As part of the application, we will provide additional back-up information, including updated data and models, to support the request. We would like to meet with the Department to discuss the Plan in preparation for our site certification modification request. If these discussions yield additional measures, FPL will update the Department prior to the December 28, 2020 deadline.

Should you have any questions, please do not hesitate to call me at 561-691-2406.

Sincerely,



Danielle L. Hall
Environmental Services Manager

CC:
Marc Harris, FDEP
Allan Stodghill, FDEP
Cindy Mulkey, FDEP
Lee Hefty, MDC
Drew Bartlett, SFWMD

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

In the Matter of an
Application for Permit by:

CERTIFIED MAIL
RETURN RECIEPT REQUESTED

Turkey Point Power Plant
9760 S.W. 344 Street
Florida City, FL 34428

DEP File # FL0001562-004-IW1N/NR
Miami-Dade County
Florida Power & Light Company

Attention: Mr. Terry O. Jones

NOTICE OF PERMIT

Enclosed is Permit Number FL0001562, issued under Section 403.0885, Florida Statutes and DEP Chapter 62-620, Florida Administrative Code, authorizing renewal of a "No Discharge" NPDES permit for internal discharge to an onsite closed-loop recirculating cooling canal system at the Turkey Point Power Plant located at 9670 S.W. 344 Street, Florida City, Miami-Dade County, Florida.

Any party to this order (permit) has the right to seek judicial review of the permit under section 120.68 of the Florida Statutes, by the filing of a Notice of Appeal under rule 9.110 of the Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000 and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within thirty days after this notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Mimi Drew
Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 12
PARTY: MWS-8
DESCRIPTION: NPDES/IWW Permit Number FL0001562

FPL
Turkey Point Power Plant
Permit Number FL0001562

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52, Florida Statutes, with the designated deputy clerk, receipt of which is hereby acknowledged.

S. Shields 05-13-05
Clerk Date

Copies furnished to:

Roosevelt Childress, EPA
Chairman, Miami-Dade County Board of Commissioners
Tim Powell, P.E., DEP SED, West Palm Beach
Buck Oven, P.E., DEP Tallahassee
Betsy Hewitt, DEP Tallahassee (w/o enclosure)

SECOND AMENDMENT TO THE FACT SHEET

DATE: January 28, 2004

PERMIT NUMBER: FL0001562

PERMITTEE: Florida Power & Light Company
Turkey Point Power Plant

The following minor corrections have been made to the proposed permit. None of these corrections alter any of the discharge limitations monitoring requirements in the permit.

1. Permittee Comments

The Permittee requested the following minor corrections to the permit.

Typographical errors in the Draft Permit: The Applicant pointed out several typographical errors by the Department which are not listed in the items below. The Department has corrected these errors, which were non-substantive and did not affect any permit limitations or monitoring requirements.

Condition I.A.6.&7. The Permittee pointed out that that previous permits did not include these conditions, which refer to floating foam and visible sheen on surface waters of the state due to discharge of wastewater. The Permittee noted that the conditions are not appropriate because the facility does not discharge to surface waters. The Department concurs, and notes that it included the conditions in error. The conditions have been deleted from the final permit.

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:

Florida Power & Light Company
9760 S.W. 344 Street
Florida City, FL 33035

PERMIT NUMBER: FL0001562 (Major)
PA FILE NUMBER: FL0001562-004-IW1N
ISSUANCE DATE: May 6, 2005
EXPIRATION DATE: May 5, 2010

RESPONSIBLE AUTHORITY:

Mr. Terry O. Jones
Vice President

FACILITY:

FPL Turkey Point Power Plant
9760 S.W. 344 Street
Florida City, FL 33035
Dade County

Latitude: See Note Below Longitude: See Note Below

Note: Latitude and longitude are not shown at Permittee's request, for purposes of Homeland Security pursuant to federal regulations found at 18 CFR 388.113(c)(i) and (ii) and by Presidential Directive dated December 17, 2003.

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.) and applicable rules of the Florida Administrative Code (F.A.C.), and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System (NPDES). The above named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

The facility consists of four steam-electric generating units: Two fossil fuel oil-fired units (Units 1&2) and two nuclear units (Units 3&4). Units 1&2 each have a continuous generating capability of 404 megawatts (MW), and Units 3&4 each have a continuous generating capability of 693 MW.

WASTEWATER TREATMENT:

Wastewater from the Turkey Point facility consists of a non-contact once-through condenser cooling water (OTCW), auxiliary equipment cooling water (AECW), low-volume waste (LVW), and stormwater. LVW consists of chemical treatment system wastewater, boiler blowdown, reverse osmosis concentrate, condensate polishing system backwash water, and other process wastestreams. Stormwater includes stormwater associated with industrial activity and stormwater not associated with industrial activity.

OTCW and AECW discharge to the facility's approximately 6,700 acre onsite closed loop cooling canal system. LVW, equipment area stormwater, and non-equipment area stormwater/drainage discharge either directly to the onsite closed loop cooling canal system or indirectly to the same system via solids settling basins and/or neutralization basin. The cooling canal system is not lined, and therefore, discharges to Class G-III groundwater. The cooling canal system does not discharge to surface waters of the state.

PERMITTEE:	PERMIT NUMBER:	FL0001562
Florida Power & Light Company 9760 S.W. 344 Street Florida City, FL 33035	Issuance date: Expiration date:	May 6, 2005 May 5, 2010

EFFLUENT DISPOSAL:

Surface Water Discharge:

This permit does not authorize discharge to surface waters of the state.

Internal Outfalls:

This permit authorizes discharge from existing internal outfalls I-001 and I-002 to the facility's onsite closed loop cooling canal system.

Groundwater Discharge

This permit authorizes an existing discharge from the onsite closed loop cooling canal system to the surficial aquifer which is a Class G-III groundwater.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions as set forth in Part I through Part VIII on pages 3 through 14 of this permit.

PERMITTEE:

Florida Power & Light Company
9760 S.W. 344 Street
Florida City, FL 33035

PERMIT NUMBER: FL0001562

Issuance date: May 6, 2005
Expiration date: May 5, 2010

I. Effluent Limitations and Monitoring Requirements

A. Surface Water Discharges

1. This permit does not authorize discharge to surface waters of the state.

2. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge non process wastewater consisting of non-contact once-through condenser cooling water (OTCW), non-contact auxiliary equipment cooling water (AECW), and other wastestreams (as indicated in the permit renewal application) from Internal Outfall I-001 to the onsite feeder canal within the facility's onsite closed loop cooling canal system. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	**Maximum Daily Average**	**Daily Maximum**	**Daily Minimum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Temperature (F), Water (DEG.F)	--	Report	--	Monthly	Instantaneous	OUI-1
Solids, Total Suspended (MG/L)	--	Report	--	Quarterly	Grab	OUI-1
pH (SU)	--	Report	Report	Quarterly	Grab	OUI-1
Salinity (PPT)	--	Report	--	Quarterly	Grab	OUI-1
Specific Conductance (UMHO/CM)	--	Report	--	Quarterly	Grab	OUI-1
Copper, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-1
Iron, Total Recoverable (MG/L)	--	Report	--	Semiannually	Grab	OUI-1
Zinc, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-1

3. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.2. and as described below:

Sample Point	Description of Monitoring Location
OUI-1	Cooling water discharge prior to entering the feeder canal within the closed loop cooling canal system

PERMITTEE:

Florida Power & Light Company
9760 S.W. 344 Street
Florida City, FL 33035

PERMIT NUMBER: FL0001562

Issuance date: May 6, 2005
Expiration date: May 5, 2010

4. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge process wastewater and stormwater from Internal Outfall I-002 into the facility's onsite closed loop cooling canal system. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	**Monthly Average**	**Daily Maximum**	**Daily Minimum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Solids, Total Suspended (MG/L)	--	Report	--	Semiannually	Grab	OUI-2
PH (SU)	--	Report	Report	Monthly	Grab	OUI-2
Specific Conductance (UMHO/CM)	--	Report	--	Quarterly	Grab	OUI-2
Lead, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-2
Oil and Grease (MG/L)	--	Report	--	Semiannually	Grab	OUI-2
Copper, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-2
Zinc, Total Recoverable (UG/L)	--	Report	--	Semiannually	Grab	OUI-2

5. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.4. and as described below:

Sample Point	Description of Monitoring Location
OUI-2	discharge from the two solids settling basins or neutralization basin prior to mixing with water in the closed loop cooling canal system

B. Underground Injection Control Systems

1. This section is not applicable to this permit. Discharge by underground injection is regulated under permit UC-13-277655.

C. Land Application Systems

1. This section is not applicable to this facility.

D. Other Methods of Disposal or Recycling

1. There shall be no discharge of industrial wastewater from this facility to ground or surface waters, except as authorized by this permit.

E. Other Limitations and Monitoring and Reporting Requirements

1. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Southeast District Office Discharge Monitoring Reports (DMRs) in accordance

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with the frequencies specified by the REPORT type (i.e., monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	DMR Due Date
Monthly or Toxicity	first day of month – last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 – June 30 July 1 – September 30 October 1 – December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 – June 30 July 1 – December 31	July 28 January 28
Annual	January 1 – December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge.

The permittee shall make copies of the attached DMR form(s) and shall submit the completed DMR form(s) to the Department's Southeast District Office at the address specified in Permit Condition I.E.2.

2. Unless specified otherwise in this permit, all reports and notifications required by this permit, including twenty-four hour notifications, shall be submitted to or reported to the Southeast District Office at the address specified below:

   Southeast District Office
   400 North Congress, Suite 200
   West Palm Beach, FL 33401-3303

   Phone Number - (561) 681-6702

3. All reports and other information shall be signed in accordance with requirements of Rule 62-620.305, F.A.C.

4. The permittee shall provide safe access points for obtaining representative samples which are required by this permit.

5. If there is no discharge from the facility on a day scheduled for sampling, the sample shall be collected on the day of the next discharge.

6. Bypasses subject to General Conditions VIII.20 and VIII.22 shall be monitored or estimated daily, or as approved by the Department for flow and other parameters required for the specific outfall that is bypassed. Monitoring results shall be reported to the Department.

7. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

8. This permit authorizes the use of the following biocides, or their generic equivalents, in various closed cooling water systems without limitations or monitoring; NALCO 7338, NALCO 7330, NALCO 7348, BULAB 6001/6002, BETZ POWERLINE 3610. The Permittee shall notify the Department if there is a discharge of any of these products into the closed cycle cooling canal system in other than de-minimus amounts which contain concentrations of active ingredients above the MDLs for those ingredients.

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9. A permit revision from the Department shall be required prior to the use of any biocide or chemical additive, which may be toxic to aquatic life, (except as authorized elsewhere in this permit) in the cooling water system or any other portion of the industrial wastewater system. The permit revision request shall include:

   a. Name and general composition of biocide or chemical
   b. Frequencies of use
   c. Quantities to be used
   d. Proposed effluent concentrations
   e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA/600/4-90/027 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)
   f. Product data sheet
   g. Product label

   The Department shall review the above information to determine if a major or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical is not authorized without prior authorization by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

10. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit.

11. Hydrazine and Monoethanolamine (ETA) Monitoring Requirements

    a) Discharge of hydrazine, carbohydrazide, dimethylamine, and monoethanolamine (ETA) in the boiler or steam generator blowdown is authorized without limitation or monitoring requirements.
    b) Hydrazine from plant layup water during overhauls and/or refueling outages shall be measured at the outlet from the unit being serviced. Sampling shall be once per day of discharge by grab sample at the maximum expected concentration. Results of sampling will be submitted to the Department upon request. To determine the hydrazine concentration being discharged to the cooling canal system, the following equation shall be used:

$$\frac{\text{(B/S) Blowdown Flow x (B/S) Hydrazine Concentration}}{\text{Once-through Cooling Water Flow}} = \text{Hydrazine concentration at the closed cycle cooling canal system}$$

    Where (B/S) refers to boiler or steam generator

    In the event that any value exceeds 3.4 mg/l, the permittee shall immediately modify its release pattern and resample. The Department's Southeast District office will be notified of the situation within five days.

12. Molybdate, Tolytriazole, and Nitrite Discharge Requirements
    The discharge of molybdate, tolytriazole, and nitrite to the closed cycle recirculating cooling canal system during maintenance of the auxiliary closed water system is allowed without limitations and monitoring requirements.

13. Non-discharging/Closed Loop Vehicle Wash Recycle System Requirements

    a) No discharge of recycle system wastewater, including filter backwash water, is authorized to surface water or to ground water.

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b) The rainwater diversion system shall be operated in accordance with the facility's Best Management Practice Procedure as indicated on amended drawing No. 297-036, Alternate No. 6, signed and sealed 4/23/99.

c) A placard shall be conspicuously posted in the area of the non-discharging/closed loop recycle equipment which indicates the proper operation of the rainwater diversion system i.e. TRUCK WASH RAINWATER VALVE OPERATING PROCEDURE as indicated on amended drawing No. 297-036 Alternate No. 6, signed and sealed 4/23/99.

d) d) Spent process wastewater shall be disposed of at a Department permitted wastewater treatment facility which is capable of treating the wastewater.

e) Any oil collected from the oil/water separator shall be disposed by a licensed used oil recycler in accordance with Florida Administrative Code 62-710 or otherwise recycled on site through Department approved methods and procedures.

f) Any accidental discharge to ground water or surface water shall be reported to the Southeast District office.

14. Notwithstanding any other requirements of this "No Discharge" permit, the permittee shall comply with all applicable provisions of the Final Judgement dated September 10, 1971, in Civil Action Number 70-328-CA issued by the U.S. District Judge C. Clyde Atkins of the Southern District of Florida.

II. Industrial Sludge Management Requirements

A. Basic Management Requirements

1. Sludge or other solids generated from the facility shall be reused, reclaimed, or otherwise disposed of in accordance with the requirements of Chapter 62-701, F.A.C.

2. The permittee shall keep records at the facility of the amount of sludge or residuals disposed, transported, or incinerated. If a person other than the permittee is responsible for sludge transporting, disposal, or incineration, the permittee shall also keep the following records:

   a. name, address and telephone number of any transporter, and any manifests or bill of lading used;
   b. name and location of the site of disposal, treatment or incineration;
   c. name, address, and telephone number of the entity responsible for the disposal, treatment, or incineration site.

III. Ground Water Monitoring Requirements

1. This section is not applicable to this facility.

IV. Other Land Application Requirements

1. The Permittee's discharge to ground water shall not cause a violation of the minimum criteria for ground water specified in Rule 62-520.400, F.A.C. and 62-520.430, F.A.C.

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V. Operation and Maintenance Requirements

A. Operation of Treatment and Disposal Facilities

1. The permittee shall ensure that the operation of this facility is as described in the application and supporting documents.

2. The operation of the pollution control facilities described in this permit shall be under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control.

B. Record keeping Requirements:

1. The permittee shall maintain the following records on the site of the permitted facility and make them available for inspection:

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports, other than those required in items a. and f. of this section, required by the permit for at least three years from the date the report was prepared, unless otherwise specified by Department rule;

   c. Records of all data, including reports and documents used to complete the application for the permit for at least three years from the date the application was filed, unless otherwise specified by Department rule;

   d. A copy of the current permit;

   e. A copy of any required record drawings;

   f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date on the logs or schedule.

VI. Schedules

1. The permittee shall achieve compliance with the other conditions of this permit as follows:

   Operational level attained Issuance Date of permit

2. No later than 14 calendar days following a date identified in the above schedule(s) of compliance, the permittee shall submit either a report of progress or, in the case of specific actions being required by an identified date, a written notice of compliance or noncompliance. In the latter case, the notice shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

VII. Other Specific Conditions

A. Specific Conditions Applicable to All Permits

1. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Southeast District Office, are made a part hereof.

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2. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of reports to be submitted under this permit, shall be signed and sealed by the professional(s) who prepared them.

3. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Specific Conditions Related to Construction

I. This section is not applicable to this facility.

C. Duty to Reapply

1. The permittee shall submit an application to renew this permit at least 180 days before the expiration date of this permit.

2. The permittee shall apply for renewal of this permit on the appropriate form listed in Rule 62-620.910, F.A.C., and in the manner established in Chapter 62-620, F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.

3. An application filed in accordance with subsections 1. and 2. of this part shall be considered timely and sufficient. When an application for renewal of a permit is timely and sufficient, the existing permit shall not expire until the Department has taken final action on the application for renewal or until the last day for seeking judicial review of the agency order or a later date fixed by order of the reviewing court.

4. The late submittal of a renewal application shall be considered timely and sufficient for the purpose of extending the effectiveness of the expiring permit only if it is submitted and made complete before the expiration date.

D. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

   a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels
      (1) One hundred micrograms per liter,
      (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter for antimony, or
      (3) Five times the maximum concentration value reported for that pollutant in the permit application.

   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels
      (1) Five hundred micrograms per liter,
      (2) One milligram per liter for antimony, or
      (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

E. Reopener Clause

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1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, or other information show a need for a different limitation or monitoring requirement.

3. The Department may develop a Total Maximum Daily Load (TMDL) during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

VIII. General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, F.S. Any permit noncompliance constitutes a violation of Chapter 403, F.S., and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1), F.A.C.]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2), F.A.C.]*

3. As provided in Subsection 403.087(6), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringements of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3), F.A.C.]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4), F.A.C.]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be

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a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5), F.A.C.]*

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6), F.A.C.]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7), F.A.C.]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8), F.A.C.]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to
   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;
   b. Have access to and copy any records that shall be kept under the conditions of this permit;
   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and
   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

   [62-620.610(9), F.A.C.]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, Florida Statutes, or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10), F.A.C.]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11), F.A.C.]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12), F.A.C.]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13), F.A.C.]*

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14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the Department approves the transfer. *[62-620.610(14), F.A.C.]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15), F.A.C.]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rule 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16), F.A.C.]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:
    a. A description of the anticipated noncompliance;
    b. The period of the anticipated noncompliance, including dates and times; and
    c. Steps being taken to prevent future occurrence of the noncompliance.
    [62-620.610(17), F.A.C.]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate.
    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10).
    b. If the permittee monitors any contaminate more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.
    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.
    d. Any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health (DOH) under Chapter 64E-1, F.A.C., where such certification is required by Rule 62-160.300(4), F.A.C. The laboratory must be certified for any specific method and analyte combination that is used to comply with this permit. For domestic wastewater facilities, the on-site test procedures specified in Rule 62-160.300(4), F.A.C., shall be performed by a laboratory certified test for those parameters or under the direction of an operator certified under Chapter 62-602, F.A.C.
    e. Fields activities including on-site tests and sample collection, whether performed by a laboratory or a certified operator, must follow the applicable procedures described in DEP-SOP-001/01 (January 2002). Alternate field procedures and laboratory methods may be used where they have been approved according to the requirements of Rules 62-160.220, 62-160.330, and 62-160.600, F.A.C.
    [62-620.610(18), F.A.C.]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19), F.A.C.]*

20. The permittee shall report to the Department's Southeast District Office any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of

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the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

a. The following shall be included as information which must be reported within 24 hours under this condition:
   (1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
   (2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
   (3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
   (4) Any unauthorized discharge to surface or ground waters.

b. Oral reports as required by this subsection shall be provided as follows:
   (1) For unauthorized releases or spills of untreated or treated wastewater reported pursuant to subparagraph a.4 that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the Department by calling the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Warning Point:
      (a) Name, address, and telephone number of person reporting;
      (b) Name, address, and telephone number of permittee or responsible person for the discharge;
      (c) Date and time of the discharge and status of discharge (ongoing or ceased);
      (d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
      (e) Estimated amount of the discharge;
      (f) Location or address of the discharge;
      (g) Source and cause of the discharge;
      (h) Whether the discharge was contained on-site, and cleanup actions taken to date;
      (i) Description of area affected by the discharge, including name of water body affected, if any; and
      (j) Other persons or agencies contacted.
   (2) Oral reports, not otherwise required to be provided pursuant to subparagraph b(1) above, shall be provided to Department's Southeast District Office within 24 hours from the time the permittee becomes aware of the circumstances.

c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Southeast District Office shall waive the written report.

[62-620.610(20), F.A.C.]

21. The permittee shall report all instances of noncompliance not reported under Conditions VIII. 18 and 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Condition VIII. 20. of this permit. *[62-620.610(21), F.A.C.]*

22. Bypass Provisions.
   a. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
      (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
      (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventative maintenance; and
      (3) The permittee submitted notices as required under Condition VIII.22.b. of this permit.

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b. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Condition VIII.20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.
c. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Condition VIII.22 a. (1) through (3) of this permit.
d. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Condition VIII.22.a. through c. of this permit.
[62-620.610(22), F.A.C.]

23. Upset Provisions
a. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
(1) An upset occurred and that the permittee can identify the cause(s) of the upset;
(2) The permitted facility was at the time being properly operated;
(3) The permittee submitted notice of the upset as required in Condition VIII.20. of this permit; and
(4) The permittee complied with any remedial measures required under Condition VIII.5. of this permit.
b. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.
c. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.
[62-620.610(23), F.A.C.]

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

Mimi A. Drew
Director, Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8592

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551 , 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Florida Power & Light Company
MAILING ADDRESS: 9760 S.W. 344 Street
Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major

REPORT: Monthly
GROUP: Industrial

MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESC: non-contact once through condenser cooling water

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water	Sample Measurement										
PARM Code 00011 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	DEG.F		Monthly	Instantaneous
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (YY/MM/DD)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551 , 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Florida Power & Light Company
MAILING ADDRESS: 9760 S.W. 344 Street
Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major

REPORT: Quarterly
GROUP: Industrial

MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESC: non-contact once through condenser cooling water

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	MG/L		Quarterly	Grab
pH	Sample Measurement										
PARM Code 00400 P Mon. Site No. OUI-1	Permit Requirement					Report (Day.Min.)	Report (Day.Max.)	SU		Quarterly	Grab
Salinity	Sample Measurement										
PARM Code 00480 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	PPT		Quarterly	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	UMHO/ CM		Quarterly	Grab
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										

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Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major

REPORT: Semiannual
GROUP: Industrial

MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESC: non-contact once through condenser cooling water

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	MG/L		Semiannually	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										

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MAILING ADDRESS: 9760 S.W. 344 Street
Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major

REPORT: Monthly
GROUP: Industrial

MONITORING GROUP NUMBER: I-002
MONITORING GROUP DESC: low volume wastewater (LVW) and equipment area stormwater discharged

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH	Sample Measurement										
PARM Code 00400 P Mon. Site No. OUI-002	Permit Requirement					Report (Day.Min.)	Report (Day.Max.)	SU		Monthly	Grab
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										

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PERMITTEE NAME: Florida Power & Light Company
MAILING ADDRESS: 9760 S.W. 344 Street
Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major

REPORT: Quarterly
GROUP: Industrial

MONITORING GROUP NUMBER: I-002
MONITORING GROUP DESC: low volume wastewater (LVW) and equipment area stormwater discharged

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Specific Conductance	Sample Measurement										
PARM Code 00095 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	UMHO/ CM		Quarterly	Grab
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

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Florida City, FL 33035

FACILITY: FPL Turkey Point Power Plant
LOCATION: 9760 S.W. 344 Street
Florida City, FL 33035

COUNTY: Dade

PERMIT NUMBER FL0001562

LIMIT: Final
CLASS SIZE: Major

REPORT: Semiannual
GROUP: Industrial

MONITORING GROUP NUMBER: I-002
MONITORING GROUP DESC: low volume wastewater (LVW) and equipment area stormwater discharged

NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	MG/L		Semiannually	Grab
Lead, Total Recoverable	Sample Measurement										
PARM Code 01114 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
Oil and Grease	Sample Measurement										
PARM Code 00556 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	MG/L		Semiannually	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 P Mon. Site No. OUI-002	Permit Requirement						Report (Day.Max.)	UG/L		Semiannually	Grab
	Sample Measurement										
	Permit Requirement										

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT

Read these instructions as well as the SUPPLEMENTAL INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT before completing the DMR. Hard copies and/or electronic copies of the required parts of the DMR were provided with the permit. All required information shall be completed in full and typed or printed in ink. A signed, original DMR shall be mailed to the address printed on the DMR by the 28th of the month following the monitoring period. The DMR shall not be submitted before the end of the monitoring period.

The DMR consists of three parts--A, B, and D--all of which may or may not be applicable to every facility. Facilities may have one or more Part A's for reporting effluent or reclaimed water data. All domestic wastewater facilities will have a Part B for reporting daily sample results. Part D is used for reporting ground water monitoring well data.
When results are not available, the following codes should be used on parts A and D of the DMR and an explanation provided where appropriate. Note: Codes used on Part B for raw data are different.

CODE	DESCRIPTION/INSTRUCTIONS
ANC	Analysis not conducted.
DRY	Dry Well
FLD	Flood disaster.
IFS	Insufficient flow for sampling.
LS	Lost sample.
MNR	Monitoring not required this period.

CODE	DESCRIPTION/INSTRUCTIONS
NOD	No discharge from/to site.
OPS	Operations were shutdown so no sample could be taken.
OTH	Other. Please enter an explanation of why monitoring data were not available.
SEF	Sampling equipment failure.

When reporting analytical results that fall below a laboratory's reported method detection limits or practical quantification limits, the following instructions should be used:

1. Results greater than or equal to the PQL shall be reported as the measured quantity.
2. Results less than the PQL and greater than or equal to the MDL shall be reported as the laboratory's MDL value. These values shall be deemed equal to the MDL when necessary to calculate an average for that parameter and when determining compliance with permit limits.
3. Results less than the MDL shall be reported by entering a less than sign ("<") followed by the laboratory's MDL value, e.g. < 0.001. A value of one-half the MDL or one-half the effluent limit, whichever is lower, shall be used for that sample when necessary to calculate an average for that parameter. Values less than the MDL are considered to demonstrate compliance with an effluent limitation.

PART A -DISCHARGE MONITORING REPORT (DMR)

Part A of the DMR is comprised of one or more sections, each having its own header information. Facility information is preprinted in the header as well as the monitoring group number, whether the limits and monitoring requirements are interim or final, and the required submittal frequency (e.g. monthly, annually, quarterly, etc.). Submit Part A based on the required reporting frequency in the header and the instructions shown in the permit. The following should be completed by the permittee or authorized representative:

No Discharge From Site: Check this box if no discharge occurs and, as a result, there are no data or codes to be entered for all of the parameters on the DMR for the entire monitoring group number; however, if the monitoring group includes other monitoring locations (e.g., influent sampling), the "NOD" code should be used to individually denote those parameters for which there was no discharge.
Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Sample Measurement: Before filling in sample measurements in the table, check to see that the data collected correspond to the limit indicated on the DMR (i.e. interim or final) and that the data correspond to the monitoring group number in the header. Enter the data or calculated results for each parameter on this row in the non-shaded area above the limit. Be sure the result being entered corresponds to the appropriate statistical base code (e.g. annual average, monthly average, single sample maximum, etc.) and units.
No. Ex.: Enter the number of sample measurements during the monitoring period that exceeded the permit limit for each parameter in the non-shaded area. If none, enter zero.
Frequency of Analysis: The shaded areas in this column contain the minimum number of times the measurement is required to be made according to the permit. Enter the actual number of times the measurement was made in the space above the shaded area.
Sample Type: The shaded areas in this column contain the type of sample (e.g. grab, composite, continuous) required by the permit. Enter the actual sample type that was taken in the space above the shaded area.
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comment and Explanation of Any Violations: Use this area to explain any exceedances, any upset or by-pass events, or other items which require explanation. If more space is needed, reference all attachments in this area.

PART B - DAILY SAMPLE RESULTS

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Daily Monitoring Results: Transfer all analytical data from your facility's laboratory or a contract laboratory's data sheets for all day(s) that samples were collected. Record the data in the units indicated. Table 1 in Chapter 62-160, F.A.C., contains a complete list of all the data qualifier codes that your laboratory may use when reporting analytical results. However, when transferring numerical results onto Part B of the DMR, only the following data qualifier codes should be used and an explanation provided where appropriate.

CODE	DESCRIPTION/INSTRUCTIONS
<	The compound was analyzed for but not detected.
A	Value reported is the mean (average) of two or more determinations.
J	Estimated value, value not accurate.
Q	Sample held beyond the actual holding time.
Y	Laboratory analysis was from an unpreserved or improperly preserved sample.

Add the results to get the Total and divide by the number of days in the month to get the Monthly Average.
Plant Staffing: List the name, certificate number, and class of all state certified operators operating the facility during the monitoring period. Use additional sheets as necessary.

PART D - GROUND WATER MONITORING REPORT

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Date Sample Obtained: Enter the date the sample was taken. Also, check whether or not the well was purged before sampling.
Time Sample Obtained: Enter the time the sample was taken.
Sample Measurement: Record the results of the analysis. If the result was below the minimum detection limit, indicate that.
Detection Limits: Record the detection limits of the analytical methods used.
Analysis Method: Indicate the analytical method used. Record the method number from Chapter 62-160 or Chapter 62-601, F.A.C., or from other sources.
Sampling Equipment Used: Indicate the procedure used to collect the sample (e.g. airlift, bucket/bailer, centrifugal pump, etc.)
Samples Filtered: Indicate whether the sample obtained was filtered by laboratory (L), filtered in field (F), or unfiltered (N).
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comments and Explanation: Use this space to make any comments on or explanations of results that are unexpected. If more space is needed, reference all attachments in this area.

SPECIAL INSTRUCTIONS FOR LIMITED WET WEATHER DISCHARGES

Flow (Limited Wet Weather Discharge): Enter the measured average flow rate during the period of discharge or divide gallons discharged by duration of discharge (converted into days). Record in million gallons per day (MGD).
Flow (Upstream): Enter the average flow rate in the receiving stream upstream from the point of discharge for the period of discharge. The average flow rate can be calculated based on two measurements; one made at the start and one made at the end of the discharge period. Measurements are to be made at the upstream gauging station described in the permit.
Actual Stream Dilution Ratio: To calculate the Actual Stream Dilution Ratio, divide the average upstream flow rate by the average discharge flow rate. Enter the Actual Stream Dilution Ratio accurate to the nearest 0.1.
No. of Days the SDF > Stream Dilution Ratio: For each day of discharge, compare the minimum Stream Dilution Factor (SDF) from the permit to the calculated Stream Dilution Ratio. On Part B of the DMR, enter an asterisk (*) if the SDF is greater than the Stream Dilution Ratio on any day of discharge. On Part A of the DMR, add up the days with an "*" and record the total number of days the Stream Dilution Factor was greater than the Stream Dilution Ratio.
$CBOD_5$: Enter the average $CBOD_5$ of the reclaimed water discharged during the period shown in duration of discharge.
TKN: Enter the average TKN of the reclaimed water discharged during the period shown in duration of discharge.
Actual Rainfall: Enter the actual rainfall for each day on Part B. Enter the actual cumulative rainfall to date for this calendar year and the actual total monthly rainfall on Part A. The cumulative rainfall to date for this calendar year is the total amount of rain, in inches, that has been recorded since January 1 of the current year through the month for which this DMR contains data.
Rainfall During Average Rainfall Year: On Part A, enter the total monthly rainfall during the average rainfall year and the cumulative rainfall for the average rainfall year. The cumulative rainfall for the average rainfall year is the amount of rain, in inches, which fell during the average rainfall year from January through the month for which this DMR contains data.
No. of Days LWWD Activated During Calendar Year: Enter the cumulative number of days that the limited wet weather discharge was activated since January 1 of the current year.
Reason for Discharge: Attach to the DMR a brief explanation of the factors contributing to the need to activate the limited wet weather discharge.

FLORIDA DEPARTMENT OF Environmental Protection

Tallahassee Office
2600 Blair Stone Road, M.S. 3545
Tallahassee, Florida 32399-2400

Ron DeSantis
Governor

Jeanette Nuñez
Lt. Governor

Noah Valenstein
Secretary

April 13, 2020

SENT BY EMAIL TO:
(Brian.Stamp@fpl.com)

In the Matter of an
Application for Permit by:

Florida Power & Light Company
Mr. Brian Stamp
Plant Turkey Nuclear General Manager
9760 SW 344 Street
Florida City, Florida 33035

Miami-Dade County
Turkey Point Power Plant
NPDES Permit No. FL0001562
PA File No. FL0001562-012-IW1N

INTENT TO ISSUE

The Department of Environmental Protection gives notice of its intent to issue a permit (copy of conditions attached) for the proposed project as detailed in the application specified above, for the reasons stated below.

The applicant, Florida Power & Light Company, applied on October 22, 2009, to the Department of Environmental Protection for a permit to operate wastewater treatment and effluent disposal facilities at Turkey Point Power Plant. The facility is located at 9760 SW 344 Street, Florida City, Florida 33035 in Miami-Dade County, Florida.

The Department has permitting jurisdiction under Chapter 403, Florida Statutes (F.S.), and applicable rules of the Florida Administrative Code (F.A.C.). The project is not exempt from permitting procedures. The Department has determined that a wastewater permit is required for the proposed work.

Based upon the application and supplemental information, the Department has determined that the applicant has provided reasonable assurance that the above described wastewater project complies with the applicable provisions of Chapter 403, F.S., and Title 62 of the F.A.C.

Under Section 403.815, F.S., and Rule 62-110.106, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permit. The notice must be published one time only within 30 days of receipt of this intent to issue in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used should be one with significant

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 13
PARTY: MWS-9
DESCRIPTION: April 13, 2020 Notice of Intent to Issue Permit

circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant must provide proof of publication to the Department's Wastewater Management Program, 2600 Blair Stone Road, M.S. 3545, Tallahassee, Florida 32399-2400 within two weeks of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit under Rule 62-110.106(11), F.A.C.

NOTICE OF RIGHTS

The Department will issue the permit unless a petition for an administrative hearing is timely filed under Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. On the filing of a timely and sufficient petition, this action will not be final and effective until further order of the Department. Because the administrative hearing process is designed to formulate final agency action, the hearing process may result in a modification of the agency action or even denial of the application.

Petition for Administrative Hearing

A person whose substantial interests are affected by the Department's action may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. Pursuant to Rules 28-106.201 and 28-106.301, F.A.C., a petition for an administrative hearing must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;
(b) The name, address, any e-mail address, any facsimile number, and telephone number of the petitioner, if the petitioner is not represented by an attorney or a qualified representative; the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;
(c) A statement of when and how the petitioner received notice of the agency decision;
(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;
(e) A concise statement of the ultimate facts alleged, including the specific facts that the petitioner contends warrant reversal or modification of the agency's proposed action;
(f) A statement of the specific rules or statutes that the petitioner contends require reversal or modification of the agency's proposed action, including an explanation of how the alleged facts relate to the specific rules or statutes; and
(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wishes the agency to take with respect to the agency's proposed action.

The petition must be filed (received by the Clerk) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, or via electronic correspondence at Agency_Clerk@dep.state.fl.us. Also, a copy of the petition shall be mailed to the applicant at the address indicated above at the time of filing.

Time Period for Filing a Petition

In accordance with Rule 62-110.106(3), F.A.C., petitions for an administrative hearing by the applicant and persons entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of receipt of this written notice. Petitions filed by any persons other than the applicant, and other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of

the notice or within 14 days of receipt of the written notice, whichever occurs first. The failure to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

Extension of Time

Under Rule 62-110.106(4), F.A.C., a person whose substantial interests are affected by the Department's action may also request an extension of time to file a petition for an administrative hearing. The Department may, for good cause shown, grant the request for an extension of time. Requests for extension of time must be filed with the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, or via electronic correspondence at Agency_Clerk@dep.state.fl.us, before the deadline for filing a petition for an administrative hearing. A timely request for extension of time shall toll the running of the time period for filing a petition until the request is acted upon.

Mediation

Mediation is not available in this proceeding.

EXECUTION AND CLERKING

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Benjamin M. Melnick
Director
Division of Water Resource Management

Attachment(s):

1. Proposed Permit No. FL0001562
2. Notice of Intent to Issue Permit for newspaper publication
3. Discharge Monitoring Report
4. Fact Sheet

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this document and all attachments were sent on the filing date below to the following listed persons:

Danielle Hall, Environmental Services Manager, FPL (danielle.hall@fpl.com)
EPA Region 4 (r4npdespermits@epa.gov)
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FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to Section 120.52, F. S., with the designated Department Clerk, receipt of which is hereby acknowledged.

Shirley Shields
Clerk

April 13, 2020
Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE PERMIT

The Department of Environmental Protection gives notice of its intent to issue a permit to Florida Power & Light Company for the Turkey Point Power Plant. This permit authorizes the permittee to operate wastewater treatment and effluent disposal facilities at the Turkey Point Power Plant. The facility is located at 9760 SW 344 Street, Florida City, Florida 33035 in Miami-Dade County, Florida. The Department has assigned permit file number FL0001562-012-IW1N to the proposed project.

The intent to issue and application file are available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at the Department's Wastewater Management Program, 2600 Blair Stone Road, M.S. 3545, Tallahassee, Florida 32399-2400, at phone number (850)245-8589.

NOTICE OF RIGHTS

The Department will issue the permit unless a petition for an administrative hearing is timely filed under Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. On the filing of a timely and sufficient petition, this action will not be final and effective until further order of the Department. Because the administrative hearing process is designed to formulate final agency action, the hearing process may result in a modification of the agency action or even denial of the application.

Petition for Administrative Hearing
A person whose substantial interests are affected by the Department's action may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. Pursuant to Rules 28-106.201 and 28-106.301, F.A.C., a petition for an administrative hearing must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;
(b) The name, address, any e-mail address, any facsimile number, and telephone number of the petitioner, if the petitioner is not represented by an attorney or a qualified representative; the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;
(c) A statement of when and how the petitioner received notice of the Department's agency decision;
(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;
(e) A concise statement of the ultimate facts alleged, including the specific facts that the petitioner contends warrant reversal or modification of the agency's proposed action;

(f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action, including an explanation of how the alleged facts relate to the specific rules or statutes; and
(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wishes the agency to take with respect to the agency's proposed action.

The petition must be filed (received by the Clerk) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, or via electronic correspondence at Agency_Clerk@dep.state.fl.us. Also, a copy of the petition shall be mailed to the applicant at the address indicated above at the time of filing.

Time Period for Filing a Petition

Petitions filed by any persons other than the applicant, and other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the notice or within 14 days of receipt of the written notice, whichever occurs first. The failure to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

Extension of Time

Under Rule 62-110.106(4), F.A.C., a person whose substantial interests are affected by the Department's action may also request an extension of time to file a petition for an administrative hearing. The Department may, for good cause shown, grant the request for an extension of time. Requests for extension of time must be filed with the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, or via electronic correspondence at Agency_Clerk@dep.state.fl.us, before the deadline for filing a petition for an administrative hearing. A timely request for extension of time shall toll the running of the time period for filing a petition until the request is acted upon.

Mediation

Mediation is not available in this proceeding.

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:
Florida Power & Light Company (FPL)
9760 S.W. 344 Street
Florida City, Florida 33035

PERMIT NUMBER: FL0001562 (Major)
FILE NUMBER: FL0001562-012-IW1N
ISSUANCE DATE: **PROPOSED**
EXPIRATION DATE: **PROPOSED**

RESPONSIBLE OFFICIAL:

Brian Stamp
Point Turkey Nuclear (PTN) General Manager

FACILITY:

FPL Turkey Point Power Plant
9760 SW 344 Street
Florida City, Florida 33035
Miami-Dade County

Latitude: 25° 26' 09" N Longitude: 80° 19' 51" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.) and applicable rules of the Florida Administrative Code (F.A.C.), and authorizes discharges explicitly expressed in this permit. The above-named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

FACILITY DESCRIPTION:

Turkey Point (Figure 1) is located on approximately 11,000 acres in unincorporated southeast Miami-Dade County about 25 miles south of Miami and about nine miles east of Florida City and Homestead. Biscayne National Park lies adjacent to northeastern and eastern portions of the facility. The Biscayne Bay Aquatic Preserve is north northeast and southeast of the facility. Everglades National Park is to the south and west (Figure 2). The boundaries of the facility governed by this permit are provided in Figure 3. A map showing the boundaries of the Turkey Point facility, Biscayne National Park, and Biscayne Bay Aquatic Preserve is attached to this permit.

Several canals are in close proximity to the facility. West of the facility are the South Florida Water Management District (SFWMD) L-31E Canal, the historic C-106 Canal (Model Lands North Canal), and the historic C-107 Canal (Model Lands South Canal). Southeast of the facility is the Card Sound Canal and southwest and south is the SFWMD S-20 Discharge Canal. The remnant canals at Turtle Point and the Barge Basin are located east northeast and northeast of the facility, respectively.

The facility consists of three electrical generating units: two nuclear units (Units 3 and 4) and one natural gas-fired combined cycle unit (Unit 5). Units 3, 4, and 5 began commercial operation in 1972, 1973, and 2007, respectively. Units 3 and 4 each have a nominal capacity of 815 Megawatts (MW) and Unit 5 has a nominal capacity of 1209 MW. Units 3, 4 and 5 are also regulated under the Florida Electrical Power Plant Siting Act (License No. PA03-045).

FPL owns and operates a cooling canal system (CCS) at the facility, which provides wastewater treatment and effluent disposal for Units 3, 4, and 5. The CCS provides a heat removal function for the cooling water from Units 3 and 4. The heated water generated by operation of Units 3 and 4 is discharged to the recirculating CCS and returned to Units 3 and 4. The temperature of the water returned to Units 3 and 4 is regulated by the U.S. Nuclear Regulatory Commission under the Atomic Energy Act. Groundwater withdrawals from the Floridan aquifer is the source of cooling water for Unit 5, and is authorized under License No. PA03-045.

WASTEWATER TREATMENT:

Stormwater and wastewater associated with power generation and ancillary activities are released to the CCS, which discharges to groundwater beneath the system.

PROPOSED

Stormwater runoff associated with loading and unloading operations, outdoor storage, outdoor process activities, and ancillary maintenance activities is directed toward and released into the CCS. The quantities of stormwater generated from these activities are dependent on many variables, including the length and intensity of the storm event. Wastewater generated by Units 3 and 4 includes intermittent chemical volume control system including wet lay-up, feedwater condensate including wet lay-up, on-line chemical analyzer, steam generator blowdown, condensate polisher backwash, reverse osmosis reject, circulating water pumps seal water, alternate flow from the circulating water pump seal water tank, non-equipment area stormwater, maintenance/wash through equipment area/closed cooling water system maintenance, plant intake screen wash, and non-contact once-through condenser cooling water (OTCW).

Wastewater generated by Unit 5 includes cooling water, emergency generator backup cooling water, non-equipment area stormwater, equipment area stormwater and plant drains following oil/water separation, and wastewater sump discharge which includes heat recovery steam generator blowdown, wastewater treatment system blowdown, and cooling water treatment reject.

REUSE OR DISPOSAL:

Groundwater Discharge: The CCS is not lined, and is authorized to discharge to Class G-III groundwater. Groundwater monitoring requirements for this facility are in accordance with Section I of this permit. The discharge shall meet the Class G-III groundwater standards of Rule 62-520.430, F.A.C. In addition, the discharge shall not impair the reasonable and beneficial use of adjacent waters beyond the facility boundary in Figure 3 in accordance with Rule 62-520.400(1)(f), F.A.C. The 1972 Environmental Impact Statement acknowledges that some seepage of water from the CCS may reach surface waters. To the extent that such seepage occurs, it shall not cause or contribute to a violation of the surface water quality standards or criteria in Chapter 62-302, F.A.C. This authorization to discharge shall not be deemed to pre-empt or prohibit the regulatory implementation, adoption, continuation or enforcement of standards or criteria established by a local government through a local pollution control program.

Surface Water Discharges: This permit does not authorize surface water discharges from the CCS through a point source to surface waters of the State.

Internal Outfall I-001: An existing permitted outfall that discharges plant process wastewater to the facility's on-site CCS.

Groundwater Monitoring Group G-001: A new permitted series that monitors groundwater.

Surface Water Monitoring Group D-01A: A new permitted series of surface water monitoring sites in Biscayne Bay, L-31E canal, S-20 canal and Card Sound canal that monitors surface waters.

Porewater Monitoring Group D-02A: A new permitted series of porewater (free water present in sediments) monitoring sites in coastal marine wetlands north, east, and south of the facility's onsite CCS.

Stormwater Discharges: This permit authorizes stormwater to be released to the facility's on-site CCS. Stormwater will intermittently include wash-down water consisting of potable water with no additives.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions as set forth in Part I through Part IX on pages 2 through 44 of this permit.

I. GROUNDWATER MONITORING REQUIREMENTS

1. The permittee's discharges to groundwater shall not cause a violation of the groundwater quality standards or criteria specified in Rules 62-520.400, 62-520.420 and 62-520.430, F.A.C., in adjacent groundwaters.[1] Compliance with this requirement shall be achieved in accordance with the Compliance Schedule in Section VI.8 - 10 of this permit as supplemented by the groundwater well monitoring in this Section.

[1] Consent Order OGC File Number 16-0241, paragraphs 19 and 20 stipulate remedial actions and timelines for achieving compliance with groundwater minimum criteria of Rule 62-520.400, F.A.C.

PROPOSED

PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
FACILITY: Turkey Point Power Plant EXPIRATION DATE:

2. The permittee's discharges to groundwater shall not impair the designated use of contiguous surface waters.[2] *[62-520.310(2)]*

3. During the period of operation authorized by this permit, the permittee shall sample groundwater from the Biscayne aquifer from the following monitoring wells, designated as **Groundwater Monitoring Group G-001,** as described below:

Monitoring Well ID	Description of Monitoring Location	Latitude			Longitude		
		o	'	"	o	'	"
TPGW-1S	West of Canal L-31E, west of northwest corner of the CCS (shallow)	25	26	4.7	80	21	15.8
TPGW-1M	West of Canal L-31E, west of northwest corner of the CCS (intermediate)	25	26	4.7	80	21	15.8
TPGW-1D	West of Canal L-31E, west of northwest corner of the CCS (deep)	25	26	4.7	80	21	15.8
TPGW-2S	West of the south-central portion of the CCS (shallow)	25	22	54.2	80	22	11.4
TPGW2M	West of the south-central portion of the CCS (intermediate)	25	22	54.2	80	22	11.4
TPGW-2D	West of the south-central portion of the CCS (deep)	25	22	54.2	80	22	11.4
TPGW-3S	South of the CCS (shallow)	25	20	42.1	80	20	51.9
TPGW-3M	South of the CCS (intermediate)	25	20	42.1	80	20	51.9
TPGW-3D	South of the CCS (deep)	25	20	42.1	80	20	51.9
TPGW-4S	Southwest Model Lands, at Tallahassee Road (shallow)	25	22	12.0	80	24	44.1
TPGW-4M	Southwest Model Lands, at Tallahassee Road (intermediate)	25	22	12.0	80	24	44.1
TPGW-4D	Southwest Model Lands, at Tallahassee Road (deep)	25	22	12.0	80	24	44.1
TPGW-5S	Northwest Model Lands – east of Tallahassee Road (shallow)	25	25	23.9	80	24	13.3
TPGW-5M	Northwest Model Lands – east of Tallahassee Road (intermediate)	25	25	23.9	80	24	13.3
TPGW-5D	Northwest Model Lands – east of Tallahassee Road (deep)	25	25	23.9	80	24	13.3
TPGW-6S	Northwest of the CCS, east of Homestead – Miami Speedway (shallow)	25	27	20.3	80	23	13.0
TPGW-6M	Northwest of the CCS, east of Homestead – Miami Speedway (intermediate)	25	27	20.3	80	23	13.0
TPGW-6D	Northwest of the CCS, east of Homestead – Miami Speedway (deep)	25	27	20.3	80	23	13.0
TPGW-7S	Northwest Model Lands (shallow)	25	26	02.5	80	25	40.7
TPGW-7M	Northwest Model Lands (intermediate)	25	26	02.5	80	25	40.7
TPGW-7D	Northwest Model Lands (deep)	25	26	02.5	80	25	40.7
TPGW-8S	West central Model Lands (shallow)	25	24	36.4	80	27	08.7
TPGW-8M	West central Model Lands (intermediate)	25	24	36.4	80	27	08.7
TPGW-8D	West central Model Lands (deep)	25	24	36.4	80	27	08.7
TPGW-9S	West of Card Sound Canal Road, southwest of CCS (shallow)	25	22	28.6	80	28	41.9
TPGW-9M	West of Card Sound Canal Road, southwest of CCS (intermediate)	25	22	28.6	80	28	41.9
TPGW-9D	West of Card Sound Canal Road, southwest of CCS (deep)	25	22	28.6	80	28	41.9
TPGW-10S	Biscayne Bay, channel entrance to Barge Basin (shallow)	25	26	27.4	80	19	29.0
TPGW-10M	Biscayne Bay, channel entrance to Barge Basin (intermediate)	25	26	27.4	80	19	29.0
TPGW-10D	Biscayne Bay, channel entrance to Barge Basin (deep)	25	26	27.4	80	19	29.0
TPGW-11S	Biscayne Bay, east of the CCS (shallow)	25	23	49.4	80	18	15.0
TPGW-11M	Biscayne Bay, east of the CCS (intermediate)	25	23	49.4	80	18	15.0
TPGW-11D	Biscayne Bay, east of the CCS (deep)	25	23	49.4	80	18	15.0
TPGW-12S	North of the CCS (shallow)	25	26	55.4	80	20	22.9
TPGW-12M	North of the CCS (intermediate)	25	26	55.4	80	20	22.9
TPGW-12D	North of the CCS (deep)	25	26	55.4	80	20	22.9
TPGW-13S	In the central portion of the CCS (shallow)	25	23	39.0	80	21	07.1
TPGW-13M	In the central portion of the CCS (intermediate)	25	23	39.0	80	21	07.1
TPGW-13D	In the central portion of the CCS (deep)	25	23	39.0	80	21	07.1
TPGW-14S	Biscayne Bay, southeast of the CCS (shallow)	25	21	15.5	80	19	34.5
TPGW-14M	Biscayne Bay, southeast of the CCS (intermediate)	25	21	15.5	80	19	34.5
TPGW-14D	Biscayne Bay, southeast of the CCS (deep)	25	21	15.5	80	19	34.5
TPGW-15S	Northwest corner of CCS (shallow)	25	25	56.9	80	21	2.5

[2] Consent Order OGC File Number 16-0241, paragraphs 19 and 21 stipulate actions and timelines to prevent violations subsection 62-520.310(2), F.A.C.

PROPOSED

PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
FACILITY: Turkey Point Power Plant EXPIRATION DATE:

Monitoring Well ID	Description of Monitoring Location	Latitude			Longitude		
		o	'	"	o	'	"
TPGW-15M	Northwest corner of CCS (intermediate)	25	25	56.9	80	21	2.5
TPGW-15D	Northwest corner of CCS (deep)	25	25	56.9	80	21	2.5
TPGW-16S	East of the south-central portion of the CCS (shallow)	25	22	37.7	80	19	53.8
TPGW-16M	East of the south-central portion of the CCS (intermediate)	25	22	37.7	80	19	53.8
TPGW-16D	East of the south-central portion of the CCS (deep)	25	22	37.7	80	19	53.8
TPGW-17S	East of the L-31E canal, adjacent to S-20 structure (shallow)	25	22	1.4	80	22	32.2
TPGW-17M	East of the L-31E canal, adjacent to S-20 structure (intermediate)	25	22	1.4	80	22	32.2
TPGW-17D	East of the L-31E canal, adjacent to S-20 structure (deep)	25	22	1.4	80	22	32.2
TPGW-18S	Model Lands, west of L-3 (shallow)	25	25	12.5	80	22	17.8
TPGW-18M	Model Lands, west of L-3 (intermediate)	25	25	12.5	80	22	17.8
TPGW-18D	Model Lands, west of L-3 (deep)	25	25	12.5	80	22	17.8
TPGW-19S	Model Lands, north of Florida City Canal (shallow)	25	26	54.2	80	21	31.33
TPGW-19M	Model Lands, north of Florida City Canal (intermediate)	25	26	54.2	80	21	31.33
TPGW-19D	Model Lands, north of Florida City Canal (deep)	25	26	54.2	80	21	31.33
TPGW-20D	Adjacent to City of Homestead baseball complex	25	27	9.99	80	26	0.5
TPGW-21S	Converted USGS well G-3164 (shallow)	25	25	20.2	80	26	10
TPGW-21M	Converted USGS well G-3164 (intermediate)	25	25	20.2	80	26	10
TPGW-21D	Converted USGS well G-3164 (deep)	25	25	20.2	80	19	10
L-3	East of the L-31E canal, north-central portion of the CCS (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	25	09.7	80	21	28.7
L-5	East of the L-31E canal, south-central portion of the CCS (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	23	20.9	80	22	07.3
G-28	Tallahassee Rd, south of Model Lands basin (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	23	25.5	80	24	43.6
G-21	Tallahassee Rd, north of Model Lands basin (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	25	34.8	80	24	42.9

[62-520.600]

4. The following parameters shall be analyzed for monitoring wells identified in Permit Condition I.3. Results shall be reported in accordance with Permit Conditions II.D.3:

Parameter*	Units	Sample Type	Monitoring Frequency
Temperature	Deg F	Automated**	Quarterly
Water Level Relative to NAVD	ft	Automated	Quarterly
Specific Conductance	umhos/cm	Automated**	Quarterly
Salinity	PSU	Automated	Quarterly
Fluid Density	g/cm^3	Automated	Quarterly
pH	s.u.	Grab	Quarterly
Solids, Total Dissolved (TDS)	mg/L	Grab	Quarterly
Chloride (as Cl)	mg/L	Grab	Quarterly
Sodium, Total	mg/L	Grab	Quarterly
Calcium, Total	mg/L	Grab	Quarterly
Potassium, Total	mg/L	Grab	Quarterly
Iron, Total Recoverable	mg/L	Grab	Quarterly
Tritium[3]	pCi/L	Grab	Quarterly

[3] The permittee shall submit a summary of at least the latest twelve months of tritium results available by August 31 of each year in lieu of submitting the results on a discharge monitoring report.

PROPOSED

PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
FACILITY: Turkey Point Power Plant EXPIRATION DATE:

Parameter*	Units	Sample Type	Monitoring Frequency
Nitrogen, Ammonia, Total (as N)	mg/L	Grab	Quarterly
Ammonium ion (NH_4^+)	mg/L	Grab	Quarterly
Ammonia, Total Unionized (as NH_3)	mg/L	Grab	Quarterly
Nitrite plus Nitrate, Total (as N)	mg/L	Grab	Quarterly
Nitrogen, Kjeldahl, Total (as N)	mg/L	Grab	Quarterly
Nitrogen, Total	mg/L	Grab	Quarterly
Phosphorus, Total (as P)	mg/L	Grab	Quarterly
Phosphate, Ortho (as PO_4)	mg/L	Grab	Quarterly
Boron, Total Recoverable	mg/L	Grab	Semi-Annually
Magnesium, Total Recoverable	mg/L	Grab	Semi-Annually
Sulfate, Total	mg/L	Grab	Semi-Annually
Sulfide	mg/L	Grab	Semi-Annually

[62-520.600(11)(b)]

*The above listed parameters are report except for Nitrite plus Nitrate, Total (as N), which has a limit of 10 mg/L in samples collected from monitoring wells TPGW-L3-18, and TPGW-L5-18.

** Because L and G wells are not automated, automated parameters shall be collected as grab samples on a quarterly basis. In addition, quarterly temperature and specific conductance profiles shall be collected at 1-foot intervals.

5. Monitoring wells TPGW- 1, 4, 5, 6, 17, 18, and 19 shall serve to aid in the determination of the success of the retraction of the hypersaline plume, as set out in Section VI of this permit.

6. In accordance with Chapter 62-160, F.A.C., records of the sampling protocol shall be maintained on-site for each monitoring well. This record shall include water level, total depth of the well, volume of water in the well, volume of water removed (during analytic sampling), stabilization documentation including pH, conductivity, and temperature; time interval of purging; time sample is taken; and device(s) used for purging (including discharge rate) and sampling. All records shall be kept on site and made available to the Department upon request.

7. In the event the water quality monitoring shows an exceedance of the applicable water quality standards for Nitrite plus Nitrate, Total (as N), the permittee shall arrange for a confirmation re-sampling within 15 days after the permittee's receipt of laboratory results. If the initial results demonstrate or the re-sampling confirms groundwater exceedances, the permittee shall notify the Department in writing within 14 days of this finding and the permittee shall be required to implement Department-approved corrective action to address the water quality violation and/or impacts within the timetable provided by the Department.

8. During well sampling, water levels shall be measured on the sample day and recorded prior to evacuating the wells or collecting samples. Water level, top of well casing and land surface elevations at each well site, at a precision of plus or minus 0.01 feet using a consistent, nationally recognized datum, shall be reported on each analysis report. Prior to sampling, the field parameters shall be stabilized from each well. Sampling and purging methods in the SOPs, as allowed in Chapter 62-160, F.A.C., must be used. *[62-520.600(11)(c)]*

9. Analyses shall be conducted on unfiltered samples, unless filtered samples have been approved by the Department's Southeast District Office as being more representative of groundwater conditions. *[62-520.310(5)]*

10. If any monitoring well becomes damaged or inoperable, the permittee shall notify the Department's Southeast District Office immediately and a detailed written report shall follow within seven days. The written report shall detail what problem has occurred and remedial measures that have been taken to prevent recurrence. All monitoring well design and replacement shall be approved by the Department's Southeast District Office prior to installation. *[62-520.600(6)(l)]*

PROPOSED

PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
FACILITY: Turkey Point Power Plant EXPIRATION DATE:

11. All wells shall be plugged and abandoned in accordance with subsection 62-532.500(5), F.A.C., unless future use is intended. *[62-532.500(5)]*

12. The permittee shall provide verbal notice to the Department as soon as practical after discovery of a sinkhole within an area for the management or application of wastewater or sludge. In accordance with permit condition IX.20, the permittee shall immediately implement measures to control the entry of contaminants into waters.

II. SURFACE WATER EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Monitoring

1. Point source discharges, as defined in subsection 62-620.200(37), F.A.C., from the facility to surface waters of the State are not authorized under this permit.

2. The discharges approved by this permit shall not cause or contribute to a violation of the surface water quality standards or criteria in Rule 62-302, F.A.C.

3. The permittee shall not increase the temperature of the surrounding surface water bodies beyond the CCS periphery so as to cause substantial damage or harm to the aquatic life or vegetation therein or interfere with beneficial uses assigned to the surface water bodies. *[62-302.520(1)(a)]*

4. During the period of operation authorized by this permit, the permittee shall sample surface waters at surface water monitoring sites, designated as **Surface Water Monitoring Group D-01A,** as specified below and reported in accordance with Permit Condition II.D.3:

			Monitoring Requirements					
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Temperature, Water	Deg F	Max Max	Report Report	Daily Maximum Monthly Average	Monthly	In situ	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
pH	s.u.	Max Min	Report Report	Daily Maximum Daily Minimum	Quarterly	Grab or In situ	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Solids, Total Dissolved (TDS)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Salinity	PSU	Max	Report	Daily Maximum	Monthly	In situ	SWD- 8, 9, 10, 11, 12	
				Monthly Average	Monthly	Calculated	SWD-1	
				Monthly Average	Monthly	In situ	SWD-8, 9, 10, 11, 12	
Specific Conductance	umhos/cm	Max	Report	Daily Maximum	Quarterly	In situ	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Turbidity	NTU	Max	Report	Daily Maximum	Quarterly	Grab	SWD-8, 9, 10, 11, 12	
Nitrogen, Ammonia, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Ammonia, Total Unionized (as NH_3)	mg/L	Max	Report	Daily Maximum	Quarterly	Calculated	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Ammonium ion (NH_4^+)	mg/L	Max	Report	Daily Maximum	Quarterly	Calculated	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Nitrite plus Nitrate, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Nitrogen, Kjeldahl, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	

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			Monitoring Requirements					
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Nitrogen, Total	mg/L	Max	Report	Single Sample	Quarterly	Calculated	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Phosphate, Ortho (as PO_4)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Phosphorous, Total	mg/L	Max	Report	Single Sample	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Chlorophyll *a*	µg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Copper, Total Recoverable	µg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Iron, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Zinc, Total Recoverable	µg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Boron, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Chlorides (as Cl)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
				Monthly Average	Monthly	Calculated	SWD-1	
Magnesium, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Sodium, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Sulfate, Total	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	
Tritium[4]	pCi/L	Max	Report	Daily Maximum	Quarterly	Grab	SWD-2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12	

5. Surface water samples shall be taken at the monitoring locations described below for the parameters listed in Permit Condition II.A.4.:

Monitoring Site Number	Sample Station ID	Location	Latitude			Longitude		
			°	'	"	°	'	"
SWD-1	--	The average of the following six salinity and chlorides monitoring locations in Biscayne Bay (TPBBSW-3, TPBBSW-4, TPBBSW-5, TPBBSW-7, TPBBSW-10, TPBBSW-14).						
SWD-2	TPBBSW-3 (bottom and top)	Biscayne Bay	25	23	49.38	80	18	14.82
SWD-3	TPBBSW-4 (bottom and top)	Biscayne Bay	25	20	40.34	80	19	43.90
SWD-4	TPBBSW-5 (bottom and top)	Biscayne Bay	25	19	13.69	80	22	1.70
SWD-5	TPBBSW-7T (bottom and top)	Biscayne Bay near Turtle Point Canal Dam	25	25	9.99	80	19	42.15
SWD-6	TPBBSW-10 (bottom and top)	Biscayne Bay	25	26	27.83	80	19	22.92
SWD-7	TPBBSW-14 (bottom and top)	Biscayne Bay	25	25	15.50	80	19	34.50

[4] The permittee shall submit a summary of at least the latest twelve months of tritium results available by August of each year in lieu of submitting the results on a discharge monitoring report.

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SWD-8	TPSWC-1B (bottom) TPSWC-1T (top)	L-31E Canal	25	25	58.44	80	21	11.87
SWD-9	TPSWC-2B (bottom) TPSWC-2T (top)	L-31E Canal	25	24	21.20	80	21	46.30
SWD-10	TPSWC-3B (bottom) TPSWC-3T (top)	L-31E Canal	25	22	10.47	80	22	33.00
SWD-11	TPSWC-4B (bottom) TPSWC-4T (top)	S-20 Canal	25	21	24.10	80	22	3.00
SWD-12	TPSWC-5B (bottom) TPSWC-5T (top)	Card Sound Canal at Hotel 2 Dam	25	21	24.62	80	20	18.70

6. Top samples shall be collected 0.5 m below the water surface. Bottom samples shall be collected 0.5 m above the sediment. Bottom samples may be modified to avoid sediment in samples.

B. Internal Outfalls

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to release non-process wastewater, consisting of OTCW, AECW, cooling tower blowdown, LVW, and stormwater. LVW consists of chemical treatment system wastewater, heat recovery steam generator blowdown, reverse osmosis concentrate, and condensate polishing system backwash water. Stormwater from equipment and containment areas is treated via oil/water separators prior to entering the CCS, as indicated in the permit renewal application, from **Internal Outfall I-001** to the on-site feeder canal within the CCS. Such releases shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition II.D.3:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Temperature, Water	Deg F	Max Max	Report Report	Daily Maximum Monthly Average	Monthly	In situ	OUI-1	
Solids, Total Suspended	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	
Biochemical Oxygen Demand (BOD)	mg/L	Max	Report	Daily Maximum	Monthly	Grab	CAL-1	
Dissolved Oxygen (DO), % Saturation	Percent	Min	Report	Monthly Average	Monthly	Calculated	CAL-1	
Oxygen Reduction Potential	mv	Max	Report	Daily Maximum	Monthly	Meter	CAL-1	
pH	s.u.	Max Min	Report Report	Daily Maximum Daily Minimum	Quarterly	Grab	OUI-1	
Color	PCU	Max	Report	Daily Maximum	Monthly	Grab	OUI-1	
Solids, Total Dissolved	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	
Salinity	PSU	Max	Report	Daily Maximum	Monthly	Grab	CAL-1	See II.B.4
				Monthly Average	Monthly	Grab	CAL-1	
			Report	Annual Average	Daily	Grab	CAL-1	
Specific Conductance	µmhos/cm	Max	Report	Daily Maximum	Quarterly	Grab	CAL-1	
Turbidity	NTU	Max	Report	Daily Maximum	Quarterly	Grab	CAL-2	
Nitrogen, Ammonia, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Ammonia, Total Unionized (as NH_3)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Ammonium ion (NH_4^+)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	

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			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Nitrite plus Nitrate, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Nitrogen, Kjeldahl, Total (as N)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Nitrogen, Total	mg/L	Max	Report	Single Sample	Quarterly	Calculated	OUI-1, CAL-1	
Phosphate, Ortho (as PO_4)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Phosphorous, Total	mg/L	Max	Report	Single Sample	Quarterly	Grab	OUI-1, CAL-1	
Chlorophyll *a*	µg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1, CAL-1	
Copper, Total Recoverable	µg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1, CAL-1	
Iron, Total Recoverable	mg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1, CAL-1	
Zinc, Total Recoverable	µg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1, CAL-1	
Boron, Total Recoverable	mg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1	
Chlorides (as Cl)	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	
Magnesium, Total Recoverable	mg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1	
Sodium, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	
Sulfate, Total	mg/L	Max	Report	Daily Maximum	Semi-annually	Grab	OUI-1	
Sulfide, Total	mg/L	Max	Report	Daily Maximum	Quarterly	Grab	CAL-1	
Tritium[5]	pCi/L	Max	Report	Daily Maximum	Quarterly	Grab	OUI-1	

2. Samples shall be taken at the monitoring locations described below for the parameters listed in Permit Condition II.B.1.:

Monitoring Site Number	Sample Station ID	Location	Latitude			Longitude		
			º	'	"	º	'	"
OUI-1	--	Cooling water discharge prior to entering the feeder canal to the CCS	25	26	00.60	80	20	15.64
CAL-1	--	--	Average of CCS monitoring sites OUI-2, -3, -4, -5, -6, -7, and -8.					
CAL-2	--	--	Average of CCS monitoring sites OUI-2, -4, -7, and -8.					
OUI-2	TPSWCCS-1	Northwest corner of the CCS	25	25	56.0	80	21	00.8
OUI-3	TPSWCCS-2	Central portion of the CCS	25	23	39.0	80	21	06.7
OUI-4	TPSWCCS-3	Southwestern portion of the CCS	25	21	52.4	80	22	02.4
OUI-5	TPSWCCS-4	Southern portion of the CCS near the Hotel 2 Dam	25	21	25.3	80	20	23.1
OUI-6	TPSWCCS-5	East-central portion of the CCS	25	23	18.4	80	19	54.4
OUI-7	TPSWCCS-6	Northeastern portion of the CCS	25	25	56.2	80	19	40.2
OUI-8	TPSWCCS-7	West-central portion of the CCS	25	24	07.6	80	21	39.4

[5] The permittee shall submit a summary of at least the latest twelve months of tritium results available by August of each year in lieu of submitting the results on a discharge monitoring report.

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3. The daily salinity readings from the CCS shall be compiled each quarter to create a quarterly average for each of the CCS. The automated hourly data as well as the analytical results from the existing individual stations shall be made available via FPL's EDMS.

4. FPL shall, when monitoring the salinity levels in the CCS, utilize all available monitoring resources in the CCS to obtain the average annual salinity rate. Specific monitoring points may not be excluded from the calculation unless such exclusion is allowed by the Department based upon a scientific reason. For the purposes of determining average annual salinities for the CCS, FPL shall use qualified hourly data (pursuant to the approved 2009 Monitoring Plan QAPP) from each of the CCS monitoring sites TPSWCCS-1, 2, 3, 4, 5, 6, and 7 collected beginning at 00:00 through 23:59 each day. The qualified hourly data for the day will be summed and divided by the number of qualified hourly values for the station that day. Stations with fewer than 12 qualified hourly data values in a given day shall not be used in the calculation of the CCS daily average. The daily averages for all qualified stations (up to seven per day) for a given day will be summed and divided by the number of qualified stations for that day to produce a qualified CCS daily average salinity value. The average annual salinity is calculated by summing the qualified CCS daily average salinity values from June 1st through May 31st and dividing the value by the number of days in the year. *[Consent Order OGC File Number 16-0241, paragraph 29.j]*

5. The permittee shall submit to the Tallahassee Wastewater Management Program a copy of the Turkey Point Annual Crocodile Monitoring Report, and a copy of the Ecological Monitoring section and associated data contained in the Turkey Point Plant Annual Monitoring Report required by Conditions XVII.C and X, respectively, of the Conditions of Certification (License No. PA 03-45). In addition, the permittee shall provide a copy of comments or findings to the Department upon request.

C. Porewater Monitoring

1. During the period of operation authorized by this permit, the permittee shall sample porewater (free water present in sediments) from coastal marine wetlands north, east, and south of the CCS from monitoring sites, designated as **Porewater Outfall D-02A,** at locations described below in accordance with the protocols set forth in FPL's Quality Assurance Project Plan dated 2013:

Porewater Monitoring ID	Description of Monitoring Location	Latitude			Longitude		
PW M1-2	Coastal marine wetlands; ½ mile north of power block	25	26	49.8	80	19	57.7
PW M2-2	Coastal marine wetlands; east of CCS, 2 miles south of power block	25	24	18.8	80	19	47.6
PW M3-2	Coastal marine wetlands; east of CCS, 3.4 miles south of power block	25	23	4.2	80	19	40.6
PW M4-2	Coastal marine wetlands; southeast corner of CCS	25	21	16.8	80	19	44.9
PW M5-2	Coastal marine wetlands; south of CCS	25	20	56	80	20	33

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PW M6-1	Coastal marine wetlands; west of Card Sound Road (background location)	25	17	40.1	80	23	46.8

2. During the period of operation authorized by this permit, the permittee shall sample porewater as specified below and reported in accordance with Permit Condition II.D.3.

Parameter*	Units	Sample Type	Monitoring Frequency
Temperature	Deg F	Grab	Semi-Annually
pH	s.u.	Grab	Semi-Annually
Specific Conductance	µmhos/cm	Grab	Semi-Annually
Salinity	PSU	Grab	Semi-Annually
Fluid Density	g/ml	Grab	Semi-Annually
Solids, Total Dissolved (TDS)	mg/L	Grab	Semi-Annually
Chloride (as Cl)	mg/L	Grab	Semi-Annually
Sodium, Total Recoverable	mg/L	Grab	Semi-Annually
Calcium, Total Recoverable	mg/L	Grab	Semi-Annually
Potassium, Total	mg/L	Grab	Semi-Annually
Boron, Total Recoverable	mg/L	Grab	Semi-Annually
Copper, Total Recoverable	ug/L	Grab	Semi-Annually
Iron, Total Recoverable	mg/L	Grab	Semi-Annually
Magnesium, Total Recoverable	mg/L	Grab	Semi-Annually

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Zinc, Total Recoverable	ug/L	Grab	Semi-Annually
Sulfate, Total	mg/L	Grab	Semi-Annually
Tritium[5]	pCi/L	Grab	Semi-Annually
Nitrogen, Ammonia, Total (as N)	mg/L	Grab	Semi-Annually
Ammonium ion (as NH_4)	mg/L	Grab	Semi-Annually
Ammonia, Total Unionized (as NH_3)	mg/L	Grab	Semi-Annually
Nitrite plus Nitrate, Total (as N)	mg/L	Grab	Semi-Annually
Nitrogen, Kjeldahl, Total (as N)	mg/L	Grab	Semi-Annually
Nitrogen, Total (as N)	mg/L	Grab	Semi-Annually
Phosphorus, Total (as P)	mg/L	Grab	Semi-Annually
Phosphate, Ortho (as PO_4)	mg/L	Grab	Semi-Annually

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D. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with a Department-approved methodology or in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in Chapter 62-302, F.A.C.; and

c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

When the analytical results are below method detection or practical quantitation limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report.

Where necessary, the permittee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permittee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

3. Monitoring requirements under this permit are effective on the first day of the second month following the effective date of the permit. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e., monthly, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Unless specified otherwise in this permit, monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below. DMRs shall be submitted for each required monitoring period including periods of no release of wastewater.

4.

REPORT Type on DMR	Monitoring Period	Submit by
Monthly	first day of month – last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 – June 30 July 1 – September 30 October 1 – December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 – June 30 July 1 – December 31	July 28 January 28
Annual	January 1 – December 31	January 28

The permittee shall use the electronic DMR system approved by the Department (EzDMR) and shall electronically submit the sample results as an attachment to the EzDMR submittal, in accordance with Permit Condition I.C.3., using the DEP Business Portal at http://www.fldepportal.com/go/, unless the permittee has a waiver from the Department in accordance with 40 CFR 127.15. Reports shall be submitted to the Department by the twenty-eighth (28th) of the month following the month of operation.

[62-620.610(18)]

5. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications, shall be submitted to or reported to, as appropriate, the Department's Southeast District Office at the address specified below:

Florida Department of Environmental Protection
Southeast District
3301 Gun Club Road, MSC7210-1
West Palm Beach, Florida 33406

Phone Number - (561) 681- 6600

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FAX Number - (561) 681-6755 (All FAX copies shall be followed by original copies.)

[62-620.305]

6. All reports and other information shall be signed in accordance with the requirements of Rules 62-620.305 and 62-620.310, F.A.C. *[62-620.305, 62-620.310]*

7. If there is no release of wastewater from internal outfall I-001 on a day when the facility would normally sample, the sample shall be collected on the day of the next release. *[62-620.320(6)]*

8. Wastewater shall not contain components that, alone or in combination with other substances or in combination with other components of the discharge:

   a. Settle to form putrescent deposits; or
   b. Float as debris, scum, oil, or other matter in such amounts as to form nuisances; or
   c. Produce color, odor, turbidity, or other conditions in such degree as to create a nuisance; or
   d. Are acutely toxic; or
   e. Are present in concentrations which are carcinogenic, mutagenic, or teratogenic to human beings or to significant, locally occurring, wildlife or aquatic species; or
   f. Pose a serious danger to the public health, safety, or welfare.

   [62-620.320(6), 62-302.500(1)]

9. There shall be no release of polychlorinated biphenyl (PCB) compounds such as those commonly used for transformer fluid to the waters of the State or the CCS. The permittee shall dispose of all known PCB equipment, articles, and wastes either in accordance with:

   a. Department-issued permits governing soil thermal treatment (Chapter 62-713, F.A.C.) or Department-approved landfills provided the PCB concentrations meet the Florida landfill's permitted limit when concentrations are less than 50 ppm; or

   b. 40 CFR 761 when concentrations are greater than or equal to 50 ppm.

   [40 CFR Part 423.12(b)(2)]

10. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream that ultimately may be released to the CCS or waters of the State is prohibited unless specifically authorized elsewhere in a permit; except this requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit. In the event the permittee proposes to use water treatment chemicals, biocides, corrosion inhibitors, or additives not authorized in this permit, or not previously reported to the Department, that ultimately may be released to the CCS or waters of the State, the permittee shall notify the Department in writing a minimum of thirty (30) days prior to instituting the use of such product. The product shall not be used prior to a determination by the Department that a permit revision is not required or prior to Department approval. Such notification shall include:

    a. Name and general composition of biocide or chemical

    b. Frequencies of use

    c. Quantities to be used

    d. Proposed effluent concentrations

    e. Acute and/or chronic toxicity data (laboratory reports shall be prepared, depending on the test type, according to Section 12 of EPA document no. EPA-821-R-02-012 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, Section 10 of EPA document no. EPA-821-R-02-013 entitled, Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms or Section 10 of EPA document no. EPA-821-

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R-02-014 entitled, Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms, or most current addition)

f. Product data sheet

g. Product label

A revision to this permit is not necessary for use of products equivalent to those authorized in this permit provided the equivalent products consist of the same active ingredients and the product is applied at the same location with the same or lower concentrations of the active ingredients at the outfall. The permittee is responsible for maintaining documentation on-site which demonstrates equivalency of any new water treatment products from another vendor or manufacturer with a different product name from those listed above.

11. Discharge of any waste resulting from the combustion of toxic, hazardous, or metal cleaning wastes to any waste stream which ultimately reaches the CCS or waters of the State is prohibited, unless specifically authorized elsewhere in this permit.

12. The permittee shall not store soil or other similar erodible materials in a manner in which off-site runoff is uncontrolled, nor shall construction activities be conducted in a manner which produces uncontrolled off-site runoff unless such uncontrolled runoff has been specifically approved by the Department. "Uncontrolled" shall mean without sedimentation basin or other controls approved by the Department.

13. The permittee shall operate and maintain loading and unloading facilities in such a manner in order to preclude spillage of chemicals, etc., used at the facility, and shall take all actions necessary to clean-up and control any such spill which may occur.

14. Any water drained from the fuel oil storage tanks or other water which meets the definition of "Petroleum Contact Water" as defined in subsection 62-740.030(1), F.A.C., shall be disposed at a Department-approved facility in accordance with Chapter 62-740, F.A.C.

15. The permittee is authorized to utilize the following water treatment chemicals and biocides, or their equivalents, in the cooling water systems and other wastewater streams:

Chemical Name	Purpose	Dosage (mg/L)	Units Treated	Frequency
Hydrazine	Normal Operation Oxygen Scavenger	40 - 500	3, 4	Daily
Hydrazine	Wet Layup Oxygen Scavenger	25 - 300	3, 4	Outages Only
Carbohydrazide	Oxygen Scavenger	25 - 100	3, 4	Outages Only
Carbohydrazide	Oxygen Scavenger	60 - 700	3, 4	Daily
Dimethylamine	pH Control	0.1 - 1.0	3, 4	Daily
Monoethanolamine	pH Control	3 - 6	3, 4	Daily
Lithium Hydroxide	pH Control for Reactor Coolant System	0 - 6	3, 4	As Needed
ROClean P111	Reverse Osmosis Membrane Cleaning	150 - 300	5	Batch
Sodium Molybdate	Corrosion Inhibitor – Recirculating Cooling System	160 - 1000	All	As Needed
Tolytriazole	Corrosion Inhibitor – Copper Control	10 - 100	All	As Needed
Sodium Nitrite	Corrosion Inhibitor – Recirculating Cooling System	50 - 1500	3, 4	As Needed
Sodium Hydroxide	pH Control - Recirculating Cooling System	Maintain pH 8.5 - 11	3, 4	As Needed
Sodium Hydroxide	Reverse Osmosis Operation	Maintain pH of 9.06	5	Monthly, Batch
Sodium Hydroxide	Reverse Osmosis pH Control	Maintain pH > 8.1	3, 4	Daily
Sodium Hypochlorite 12%	Cooling Tower Biocide	Maintain 0.2 - 1 residual	5	Daily
Sodium Hypochlorite	Disinfectant/Oxidizer	1-2	Plant General Use	As Needed
Sodium Hypochlorite	Oxidize Organics	1-2	Cooling Canals	As Needed
Versene 100 (EDTA)	Reverse Osmosis Membrane Cleaning	3000 - 5200	5	Batch
Citric Acid	Reverse Osmosis Membrane Cleaning	30,000	5	Batch
Hypersperse MDC704i	Reverse Osmosis Membrane Cleaning	2.5	5	Daily

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Chemical Name	Purpose	Dosage (mg/L)	Units Treated	Frequency
ENDCOR UAN 9766 (Molybdate)	Auxiliary Equipment Cooling Water System	5 gal./mo. (solid)	5	As Needed
AZ8101 (Tolytriazole)	Auxiliary Equipment Cooling Water System	2.5 gal./mo. (solid)	5	As Needed
OPTISPERSE HP3100	Boiler Drum Corrosion Inhibitor	2 - 3	5	Daily
DEPOSITROL PY5200	Cooling Tower Deposit Control	1.3	5	Daily
DEPOSITROL BL5400	Cooling Tower Scale Inhibitor	0.75	5	Daily
Ammonium Hydroxide	pH Control	3 - 20	3, 4	Daily
Ammonium Hydroxide	Condensate and Feedwater pH Control	Maintain pH of 9.68	5	Daily
OPTISPERSE PWR6600	Iron Oxide Dispersant in Steam Gen.	0 - 1	3, 4	Outages Only
OPTISPERSE PWR6600	Iron Oxide Dispersant in Steam Gen.	< 10 ppb	3, 4	Daily
VITEC 3000	Reverse Osmosis Antiscalant – potable water supply	3	3, 4	Batch
Sodium Bisulfite 40%	Reverse Osmosis Dechlorination	2-3/1-2	3, 4	Daily
Sodium Bisulfite 40%	Dechlorination	1-2	Cooling Canals, Plant General Use	As Needed
Hydrogen Peroxide 50%	Reverse Osmosis Hydrogen Sulfide Mitigation – Well Water	7-10	3, 4	Daily
Vitec 5100	Reverse Osmosis Antiscalant	5	3, 4	Daily
Vitec 1000	Reverse Osmosis Antiscalant	2	3, 4	Daily
Wood Flour	Condenser Tube Leak Temporary Repair	200 lb/min. (Max.) Less than 1000 lb/wk	3, 4	As Needed
Quaternary Ammonium Salt	Biological Fouling Control - Recirculating Cooling System	6 - 12	3, 4	As Needed
Gluteraldehyde	Biological Fouling Control - Recirculating Cooling System	250-500	3, 4	As Needed
MBC 215 (Isothiazolin)	Biological Fouling Control - Recirculating Cooling System	15	3, 4	As Needed
Sodium Dichromate	Corrosion Inhibitor for Emergency Diesel Gen. - Recirculating Cooling System	3500 - 4500	3, 4	As Needed
Sulfuric Acid 98%	pH Control for Water Treatment Plant to Degas CO_2	Maintain pH 6 - 7	3, 4	Daily
Sulfuric Acid	Cooling Tower pH Control	350	5	Daily
Boric Acid	Process Chemical for Chemical Volume Control System	0 - 2600	3, 4	As Needed
Aluminum-based Flocculents (such as Liquid Alum, Green Bullet, WALLFLOC 5050, or Equivalent)	Coagulation of Algae and Nutrients	250 (Max.)	Cooling Canals	As Needed
Xanthene Dyes or Equivalent (Yellow, Green, Red, or Violet Dyes)	Dye Studies for Leaks or Flow Monitoring	1	Plant General Use	As Needed
Optisperse PWR6000	Dispersant	≤ 20 ppb daily use ≤ 1 mg/l during outages	3, 4	Daily

16. Hydrazine from plant layup water during overhauls and/or refueling outages shall be measured at the outlet from the unit being serviced. Sampling shall be once per day of discharge by grab sample at the maximum expected concentration. Results of sampling will be submitted to the Department upon request. To determine the hydrazine concentration being released to the CCS, the following equation shall be used:

$$\frac{\text{(B/S) Blowdown Flow x (B/S) Hydrazine Concentration}}{\text{Once-through Cooling Water Flow}} = \text{Hydrazine concentration at the recirculating cycle cooling canal system}$$

*Where (B/S) refers to boiler or steam generator

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In the event that any value exceeds 3.4 mg/L, the permittee shall immediately modify its release pattern and resample. The Department's Southeast District Office shall be notified of the situation in accordance with permit condition IX.20.

17. Non-discharging/Closed Loop Vehicle Wash Recycle System Requirements.

    a. No discharge of recycle system wastewater, including filter backwash water, is authorized to waters of the State or to groundwater.

    b. The operation of the rainwater diversion system, oil/water separator, and placard posting shall be addressed and included in the facility's Best Management Practices Pollution Prevention Plan (PLAN) in accordance with permit condition VII.

18. Nothing in this permit authorizes take for the purposes of the permittee's compliance with the federal Endangered Species Act. [40 CFR 125.98(b)(1)]

19. A revision to this permit is not necessary for the following activities:

    a. Structural changes that do not change the quality, nature, or quantity of the discharge of wastes or that do not cause water pollution to Waters of the State; and

    b. Construction, replacement or repair of components at the facility which does not change the permitted treatment works or the terms and conditions of this permit.

    Records of these activities shall be kept by the permittee (activity description, start date and length of activity). The documentation shall be kept on-site in accordance with Permit Condition V.2, and made available to Department staff upon request. *[62-620.200(26)(a) and (b)]*

20. The facility will take reasonable actions to select appropriate laboratories with sufficient capacity to avoid delay in receiving results due to backlogs. If such delay occurs, the facility will make reasonable efforts to resolve those delays. *[Consent Order OGC File Number 16-0241, paragraph 30]*

III. SLUDGE, SOLIDS, AND VEGETATIVE MATTER MANAGEMENT REQUIREMENTS

1. The permittee shall be responsible for proper treatment, management, use, and disposal of its sludges. *[62-620.320(6)]*

2. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in accordance with requirements of Chapter 62-730, F.A.C. *[62-730]*

3. Sludge or other solids generated from the facility shall be reused, reclaimed, or otherwise disposed of in accordance with the requirements of Chapter 62-701, F.A.C. Disposal of sludge in a solid waste disposal facility shall be in accordance with the requirements of Chapter 62-701, F.A.C. *[62-701]*

4. Vegetation and materials removed from intake screens and vegetation, sediments and sludge excavated from the CCS or basins must be properly stored on-site until they are disposed in accordance with requirements in Chapter 62-701, F.A.C., and other applicable State and Federal requirements. Vegetation and materials shall be handled and managed in accordance to the Best Management Practices Plan in Section VII of this permit.

5. The permittee shall keep records of the amount of industrial sludge, solids, and vegetative matter disposed, transported, or incinerated. If a person other than the permittee is responsible for sludge transporting, disposal, or incineration, the permittee shall also keep the following records:

    a. name, address and telephone number of any transporter, and any manifests or bill of lading used;

    b. name and location of the site of disposal, treatment or incineration;

    c. name, address, and telephone number of the entity responsible for the disposal, treatment, or incineration site.

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IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

Section IV is not applicable to this facility.

V. CONSTRUCTION, OPERATION AND MAINTENANCE REQUIREMENTS

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports required by the permit for at least three years from the date the report was prepared;

   c. Records of all data, including reports and documents, used to complete the application for this permit for at least three years from the date the application was filed;

   d. Records of all disposal of vegetation and materials removed from intake screens and vegetation, sediments and sludge removed from wastewater and stormwater basins;

   e. A copy of the current permit;

   f. A copy of any required record drawings;

   g. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules; and

   h. All pertinent impoundment permits, design, construction, operation, and maintenance information, including but not limited to, plans, geotechnical and structural integrity studies, copies of permits, associated certifications by qualified, State-registered professional engineer, and regulatory approvals.

   [62-620.350]

3. During the period of operation authorized by this permit, the wastewater facility shall, as part of the regular maintenance schedule, review the structural integrity of all outfalls, including all outfalls which have been taken out of service.

VI. SCHEDULES

1. The following improvement actions shall be completed according to the following schedule. The Plan shall be prepared and implemented in accordance with Part VII of this permit.

Improvement Action	Completion Date
1. Develop Best Management Practices Plan (Plan)	Effective date of permit plus 18 months
2. Implement Plan	Effective date of permit plus 30 months
3. Plan Summary	Effective date of permit plus 3 years

2. If the permittee plans to continue operation of this wastewater facility after the expiration date of this permit, the permittee shall submit an application for renewal no later than one-hundred and eighty days (180) prior to the expiration date of this permit. Application shall be made using the appropriate forms listed in Rule 62-620.910, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.

   [62-620.335(1) and (2)]

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3. The permittee shall submit to the Department's Tallahassee Wastewater Management Program an annual report by August of each year as described in permit condition VIII.G.1. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the report shall be signed and sealed by the professional(s) who prepared them.

4. The facility shall submit annually by August of each year, following permit issuance, a nutrient monitoring summary report based on 12 months of groundwater, surface water, and CCS monitoring data to the Department's Tallahassee Wastewater Management Program. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the report shall be signed and sealed by the professional(s) who prepared them. The report shall include by station and depth where specified:

   a. Annual geometric mean (AGM) concentrations by nutrient parameter;

   b. Arithmetic mean;

   c. Percentiles including 25^{th}, 75^{th}, and 90^{th}, number of samples collected by parameter; and

   d. Evaluation of trends over the period of record by parameter.

5. In lieu of submitting the results on a discharge monitoring report, the permittee shall submit to the Department's Tallahassee Wastewater Management Program and Southeast District Office a summary of at least the latest twelve months of tritium results for all locations where tritium is monitored by August of each year. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the report shall be signed and sealed by the professional(s) who prepared them.

6. In lieu of submitting the results on a discharge monitoring report, the permittee shall submit to the Department's Tallahassee Wastewater Management Program and Southeast District Office a summary of at least the latest twelve months for all parameters listed in permit condition I.4 in all wells listed in permit condition I.3 by August of each year. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the report shall be signed and sealed by the professional(s) who prepared them.

7. The permittee shall notify the Department's Tallahassee Wastewater Management Program following completion of the scheduled January 1, 2019 demolition and fill of the solids settling basins that formerly serviced Units 1 and 2.

8. The phrase "hypersaline water" as used in this permit means water that exceeds 19,000 mg/L chlorides. Location, volume and movement of the hypersaline plume shall be determined by Continuous Surface Electromagnetic Mapping ("CSEM") technology, as supplemented by data from the groundwater monitoring wells in Section I.

9. The permittee shall halt the westward migration of the hypersaline plume from the CCS within three years of the commencement of the remediation project (May 15, 2018). For determining compliance, the westward migration of the hypersaline plume shall be deemed halted if the third CSEM survey shows no net increase in hypersaline water volume and no net westward movement in the leading edge of the hypersaline plume. To ensure overall remediation objectives are attained in a timely manner, if the second CSEM survey indicates that the net westward migration of the hypersaline plume is not being halted, then, within 180 days of the second CSEM survey, the permittee shall develop and submit for approval to the Department a plan with specific actions to achieve the objectives of the remediation project. If the third CSEM survey still indicates the net westward migration of the hypersaline plume has not halted, the permittee shall implement the approved additional measures consistent with the Department approved schedule.

10. The permittee shall retract the hypersaline plume to the L-31E canal within ten years of the commencement of the remediation project (May 15, 2018). At the conclusion of the fifth year of operation of the remediation project (May 16, 2023), the permittee shall evaluate and report to the Department, within 180 days, the effectiveness of the system in retracting the hypersaline plume to the L-31E canal within 10 years. If this report shows the remediation project will not retract the hypersaline plume to the L-31E canal within 10 years due to adverse environmental impacts of remedial measures or other technical issues, the permittee shall provide an alternate plan for Department review and approval. The permittee shall begin implementing the alternate plan. in accordance with the Department approved schedule.

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VII. BEST MANAGEMENT PRACTICES PLAN (PLAN)

A. General

Through implementation of the Plan the permittee shall prevent or minimize the generation and the potential for the release of pollutants (including mercury, copper, iron, zinc, and nutrients) from facility operations (including spillage, leaks, and material and waste handling and storage activities) to industrial wastewater and stormwater. The permittee must implement the provisions of the Plan required under this Part as a condition of this permit.

In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement the Plan for the facility covered by this permit, prepared in accordance with good engineering practices and in accordance with the factors outlined in 40 CFR §125.3(d)(2) or (3) as appropriate. Paragraph 62-620.100(3)(m), F.A.C., incorporates by reference 40 CFR 122.44(k), which contains guidelines for requiring Best Management Practices (BMPs) for facilities and activities regulated under Section 403.0885, F.S.

1. The Plan shall include industrial wastewater and stormwater BMPs. The Plan shall be consistent with the objectives in VII.B, Industrial Wastewater Best Management Practices, and VII.C, Stormwater Best Management Practices, and the general guidance contained in the publications entitled Guidance Manual for Developing Best Management Practices (BMPs) [EPA 833-B-93-004, October 1993]; Developing Your Stormwater Pollution Prevention Plan: A Guide for Industrial Operators [EPA 833-B-09-002, February 2009] or any subsequent revisions to these guidance documents.
2. The Plan shall specify the individual(s) or position(s) within the facility organization as members of a Plan Team that are responsible for developing the Plan and assisting the facility or operations manager in its implementation, maintenance, and revision. The Plan shall clearly identify the responsibilities of each team member. The activities and responsibilities of the team shall address all aspects of the facility's Plan.
3. The Plan shall be documented in narrative form, shall include any necessary plot plans, drawings or maps, and shall be developed in accordance with good engineering practices. The Plan shall be organized and written with the following structure:
    a. Name and location of the facility.
    b. Statement of Plan policy.
    c. Structure, functions, and Standard Operating Procedures (SOPs) of the Plan committee.
    d. Specific industrial wastewater and stormwater management practices and SOPs, including, but not limited to, the following:
        1. modification of equipment, facilities, technology, processes, and procedures,
        2. reformulation or redesign of products,
        3. substitution of materials, and
        4. improvement in management, inventory control, materials handling or general operational phases of the facility.
    e. Risk identification and assessment.
    f. Reporting of Plan incidents.
    g. Materials compatibility.
    h. Good housekeeping.
    i. Preventative maintenance.
    j. Inspections and records.
    k. Security.
    l. Employee training. The Plan shall identify periodic dates for training.
4. The Plan shall contain a written statement from corporate or facility management indicating management's commitment to the goals of the Plan program. The statement shall be publicized or made known to all facility employees. Management shall also provide training the individuals responsible for implementing the Plan.
5. The Plan shall be developed and implemented in accordance with the schedule contained in Part VI of this permit.

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6. The Plan shall be signed by the permittee or their duly authorized representative in accordance with paragraphs 62-620.305(2)(a) and (b), F.A.C. The Plan shall be reviewed by appropriate facility staff and management. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) F.S., applicable portions of the Plan shall be signed and sealed by the professional(s) who prepared them.

7. The permittee shall amend the Plan whenever there is a change in the facility or in the operation of the facility which materially increases the generation of pollutants or their release or potential release to industrial wastewater or stormwater. The permittee shall also amend the Plan, as appropriate, when plant operations covered by the Plan change. Any such changes to the Plan shall be consistent with the objectives and specific requirements listed below. All changes in the Plan shall be reported to the Department in writing.

8. At any time, if the Plan proves to be ineffective in achieving the general objective of preventing and minimizing the generation of pollutants and their release and potential release to industrial wastewater and stormwater or the specific requirements listed below, this permit or the Plan shall incorporate revised Plan requirements.

9. Progress/update reports documenting schedules and implementation of the Plan shall be maintained at the facility. The reports shall discuss whether implementation schedules were met and revise any schedules, as necessary. The Plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of completed waste minimization assessment (WMA) studies shall be discussed. Results of any ongoing WMA studies, as well as any additional schedules for implementation of waste reduction practices, shall be included.

10. The permittee shall maintain the Plan, Progress/Update Reports, and other documents associated with the Plan at the facility and shall make these documents available to the Department upon request. All offices of the permittee which are required to maintain a copy of this NPDES permit shall also maintain a copy of the Plan.

11. The Department may notify the permittee at any time that the Plan does not meet one or more of the minimum requirements of this Part. Such notification shall identify those provisions of this permit which are not being met by the Plan, and identify which provisions of the Plan requires modifications in order to meet the minimum requirements of the Plan. Upon such notification, the permittee shall amend the Plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

B. Industrial Wastewater Best Management Practices

1. The permittee shall develop and amend, as needed, the Plan consistent with the following objectives for the control of pollutants:

   a. The number and quantity of pollutants and the toxicity of effluent generated, discharged or potentially discharged at the facility shall be minimized by the permittee to the extent feasible by managing each influent waste stream in the most appropriate manner.

   b. Under the Plan, and any SOPs included in the Plan, the permittee shall ensure proper operation and maintenance of the treatment facility.

   c. The permittee shall establish specific objectives for the control of pollutants by conducting the following evaluations:

      (1) Each facility component or system shall be examined for its waste minimization opportunities and its potential for causing a release of amounts of pollutants to industrial wastewater and stormwater due to equipment failure, improper operation, and natural phenomena such as rain or adverse weather, etc. The examination shall include all normal operations and ancillary activities including but not limited to material storage areas, plant site runoff, in-plant transfer, process and material handling areas, loading or unloading operations, spillage or leaks, sludge and waste disposal, and drainage from raw material storage, as applicable.

      (2) Where experience indicates a reasonable potential for equipment failure (e.g., a tank overflow or leakage), natural condition (e.g., precipitation), or other circumstances to result in amounts of pollutants reaching surface waters, the program should include a prediction of the direction, rate of

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flow and total quantity of pollutants which could be discharged from the facility as a result of each condition or circumstance.

2. The Industrial Wastewater BMPs component of the Plan shall include, at a minimum, the following items:

   a. A WMA for this facility to determine actions that could be taken to reduce waste loadings and chemical losses to all wastewater and/or stormwater streams as described Part VII.B.3, Required Components of a WMA, of this permit. It shall address both short-term and long-term opportunities for minimizing waste generation at this facility, utilizing at a minimum, applicable criteria selected from Part VII.B.3, particularly for high volume and/or high toxicity components of wastewater and stormwater streams. Initially, the WMA should focus primarily on actions that could be implemented quickly, thereby realizing tangible benefits to surface water quality. Long term goals and actions pertaining to waste reduction shall include investigation of the feasibility of eliminating toxic chemical use, instituting process changes, raw material replacements, etc.

      The permittee shall implement each waste reduction practice recommended by the WMA as soon as practicable. Any waste reduction practices which are identified but will not be implemented shall be described in the required progress/update reports, along with the factors inhibiting their adoption. Any waste reduction practices which cannot be implemented immediately shall be described in the Plan and included in a schedule of implementation.

      The permit issuing authority does not herein establish a time limit for completion of the WMA; the study may be conducted throughout the term of this permit. However, a suggested target completion date is six months after the effective date of this permit, so that the WMA results and recommended waste reduction practices may be incorporated into the Plan. Continual studies toward minimizing waste are encouraged.

      Practices which reduce pollutant loading in wastewater or stormwater discharges with a consequent increase in solid hazardous waste generation, decrease in air quality, or adverse effect to groundwater shall not be considered waste reduction for the purposes of this assessment.

   b. Specific BMPs to meet the objectives identified in Part VII.B.1 of this section, addressing each component or system capable of generating or causing a release of amounts of pollutants, and identifying specific preventative or remedial measures to be implemented.

3. Required Components of a WMA

   a. The WMA shall include an overall plant water balance, as well as internal water balances, as necessary. This information shall be used to determine any opportunities for water conservation or reuse/recycling and to determine if and where leakages might occur.

   b. A materials and risk assessment shall be developed and shall include the following:
      1. Identification of the types and quantities of materials used or manufactured (including by products produced) at the facility;
      2. Identification of the location and types of materials management activities which occur at the facility;
      3. An evaluation of the following aspects of materials compatibility: containment and storage practices for chemicals, container compatibility, chemical mixing procedures; potential mixing or compatibility problems; and specific prohibitions regarding mixing of chemicals;
      4. Technical information on human health and ecological effects of toxic or hazardous chemicals presently used or manufactured (including by products produced) or planned for future use or production; and
      5. Analyses of chemical use and waste generation, including overall plant material balances and as necessary, internal process balances, for all pollutants. (When actual measurements of the quantity of a chemical entering a wastewater or stormwater stream are not readily available, reasonable estimates should be made based on best engineering judgment.) The analyses shall address reasons for using particular chemicals, and measures or estimates of the actual and potential chemical discharges via wastewater, wastewater sludge, stormwater, air, solid waste or hazardous waste media.

   c. The WMA shall include, at a minimum, the following means of reducing pollutant discharges in wastewater streams or of otherwise minimizing wastes:

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(1) Process related source reduction measures, including any or all of the following, as appropriate:
(a) Production process changes;
(b) Improved process controls;
(c) Reduction of off specification materials;
(d) Reduction in use of toxic or hazardous materials;
(e) Chemical modifications and/or material purification;
(f) Chemical substitution employing non-toxic or less toxic alternatives;
(g) Equipment upgrades or modifications or changes in equipment use; and
(h) Implementation of the Turkey Point CCS Nutrient Management Plan (September 16, 2016), including annual reporting on progress.
(2) Housekeeping/operational changes, including waste stream segregation, inventory control, spill and leak prevention, equipment maintenance; and employee training in areas of material management and pollution prevention, good housekeeping, and spill prevention and response;
(3) In process recycling, on-site recycling and/or off-site recycling of materials;
(4) Following all source reduction and recycling practices, wastewater treatment process changes, including the use of new or improved treatment methods, such that treatment by products are less toxic to aquatic or human life; and
(5) Other means as agreed upon by the permit issuing authority and the permittee.

d. For stormwater discharges and instances where stormwater enters the wastewater treatment/disposal system or is otherwise commingled with wastewater, the WMA shall evaluate the following potential sources of stormwater contamination, at a minimum:
(1) Loading, unloading and transfer areas for dry bulk materials or liquids;
(2) Outdoor storage of raw materials or products;
(3) Outdoor manufacturing or processing activities;
(4) Dust or particulate generating processes; and
(5) On-site waste and/or sludge disposal practices.

The likelihood of stormwater contact in these areas and the potential for spills from these areas shall be considered in the evaluation. The history of leaks or spills of toxic or hazardous pollutants shall also be considered. Recommendations for changes to current practices which would reduce the potential for stormwater contamination from these areas shall be made, as necessary.

C. Stormwater Best Management Practices

1. Stormwater BMPs components of the Plan shall include, at a minimum, the following items:

a. A description of potential sources which may reasonably be expected to add pollutants to stormwater discharges from separate stormwater conveyances at the facility. The Plan shall identify all activities and materials that may potentially be pollutant sources. The Plan shall include, at a minimum:

(1) Drainage
(a) A site map indicating an outline of the portions of the drainage area of each stormwater outfall that are within the facility boundaries, each existing structural control measure to reduce pollutants in stormwater runoff, surface water bodies, locations where materials are exposed to precipitation, locations where spills or leaks identified under Item VII.C.1.a.(3) have occurred, and the locations of the following activities where such activities are exposed to precipitation: fueling stations; vehicle and equipment maintenance and/or cleaning areas; loading/unloading areas; locations used for the treatment, storage or disposal of wastes; liquid storage tanks; processing areas; and storage areas.
(b) For each area of the facility that generates stormwater discharges associated with industrial activity with a reasonable potential for containing pollutants, a prediction of the direction of flow, and an identification of the types of pollutants which are likely to be present in stormwater discharges associated with industrial activity. Factors to consider include the toxicity of chemical; quantity of chemicals used, produced or discharged; the likelihood of contact with stormwater; and

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history of leaks or spills of toxic or hazardous pollutants. Flows with a potential for causing erosion shall be identified.

(2) An inventory of the types of materials handled at the site that potentially may be exposed to precipitation. Such inventory shall include a narrative description of materials that have been handled, treated, stored or disposed in a manner to allow exposure to stormwater between the time of three years prior to the effective date of this permit and the present; method and location of on-site storage or disposal; materials management practices employed to minimize contact of materials with stormwater runoff between the time of three years prior to the effective date of this permit and the present; the location and a description of existing structural and non-structural control measures to reduce pollutants in stormwater runoff; and a description of any treatment the stormwater receives.

(3) A list of spills and leaks of toxic or hazardous pollutants that occurred at areas that are exposed to precipitation or that otherwise drain to a stormwater conveyance at the facility after the date of three years prior to the effective date of this permit. Such a list shall be updated as appropriate during the term of this permit.

(4) A summary of existing discharge sampling data describing pollutants in stormwater discharges from the facility, including a summary of sampling data collected during the term of this permit.

(5) A narrative description of the potential pollutant sources from the following activities if applicable: loading and unloading operations; outdoor storage activities; outdoor manufacturing or processing activities; dust or particulate generating processes; loading/unloading areas; and on-site waste disposal practices. The description shall specifically list any potential source of pollutants at the site and for each potential source, any pollutant or pollutant parameter (e.g. biochemical oxygen demand, etc.) of concern shall be identified.

b. A description of stormwater management controls appropriate for the facility and implement such controls. The appropriateness and priorities of controls in the Plan shall reflect identified potential sources of pollutants at the facility. The description of stormwater management controls shall address the following minimum components, including a schedule for implementing such controls:

(1) Good housekeeping requires the maintenance of areas that may contribute pollutants to stormwater discharges in a clean, orderly manner.

(2) A preventive maintenance program shall involve timely inspection and maintenance of stormwater management devices (e.g. cleaning oil/water separators, catch basins) as well as inspecting and testing facility equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to surface waters, and ensuring appropriate maintenance of such equipment and systems.

(3) Areas where potential spills that can contribute pollutants to stormwater discharges can occur and their accompanying drainage points shall be identified clearly in the Plan. Where appropriate, specifying material handling procedures, storage requirements, and use of equipment such as diversion valves in the Plan should be considered. Procedures for cleaning up spills shall be identified in the Plan and made available to the appropriate personnel. The necessary equipment to implement a cleanup should be available to personnel.

(4) In addition to or as part of the comprehensive site evaluation required under paragraph VII.C.1.c of this section, qualified facility personnel shall be identified to inspect designated equipment and areas of the facility at appropriate intervals specified in the Plan. A set of tracking or follow-up procedures shall be used to ensure that appropriate actions are taken in response to the inspections. Records of inspections shall be maintained.

(5) Employee training programs shall inform personnel responsible for implementing activities identified in the Plan or otherwise responsible for stormwater management at all levels of responsibility of the components and goals of the Plan. Training should address topics such material management and pollution prevention, good housekeeping and spill prevention and response. The Plan shall identify periodic dates for such training.

(6) A description of incidents (such as spills, or other discharges), along with other information describing the quality and quantity of stormwater discharges shall be included in the Plan required under this part.

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Inspections and maintenance activities shall be documented and records of such activities shall be incorporated into the Plan.

(7) Non-Stormwater Discharges

(a) The Plan shall include a certification that each "stormwater-only" discharge authorized under this permit has been tested or evaluated for the presence of non-stormwater discharges. (This section is not applicable to those discharges authorized under this permit that have been identified in the application as having non-stormwater components.) The certification shall include the identification of potential sources of non-stormwater at the site, a description of the results of any test and/or evaluation for the presence of non-stormwater discharges, the evaluation criteria or testing method used, the date of any testing and/or evaluation, and the on-site drainage points that were directly observed during the test. Such certification may not be feasible if the facility operating the stormwater discharge associated with industrial activity does not have access to an outfall, manhole, or other point of access to the ultimate conduit that receives the discharge. In such cases, the source identification section of the Plan shall indicate why the certification required by this part was not feasible, along with the identification of potential sources of non-stormwater at the site. A discharger that is unable to provide the certification required by this paragraph must notify the Department in accordance with paragraph VII.C.1.b.(7)(c) below.

(b) Except for flows from fire-fighting activities, sources of authorized non-stormwater discharges that are combined with stormwater discharges associated with industrial activity must be identified in the Plan. The Plan shall identify and ensure the implementation of appropriate pollution prevention measures for the non-stormwater component(s) of the discharge.

(c) Failure to Certify. Any facility that is unable to provide the certification required (testing for non-stormwater discharges), must notify the Department. If the failure to certify is caused by the inability to perform adequate tests or evaluations, such notification shall describe: the procedure of any test conducted for the presence of non-stormwater discharges; the results of such test or other relevant observations; potential sources of non-stormwater discharges to the storm sewer; and why adequate tests for such storm sewers were not feasible. Non-stormwater discharges to surface waters of the State which are not authorized by an NPDES permit are unlawful, and must be terminated or dischargers must submit appropriate NPDES permit application forms.

(8) The Plan shall identify areas which, due to topography, activities, or other factors, have a high potential for soil erosion, and identify structural, vegetative, and/or stabilization measures to be used to limit erosion.

(9) The Plan shall contain a narrative consideration of the appropriateness of traditional stormwater management practices (practices other than those which control the generation or source(s) of pollutants) used to divert, infiltrate, reuse, or otherwise manage stormwater runoff in a manner that reduces pollutants in stormwater discharges from the site. The Plan shall provide that those measures that the permittee determines to be reasonable and appropriate shall be implemented and maintained. The potential of various sources at the facility to contribute pollutants to stormwater discharges associated with industrial activity shall be considered when determining reasonable and appropriate measures. Appropriate measures may include: vegetative swales and practices; reuse of collected stormwater (such as for a process or as an irrigation source); inlet controls (such as oil/water separators); infiltration devices; and, detention or retention devices.

c. A Comprehensive Site Compliance Evaluation. Qualified personnel shall conduct site compliance evaluations at appropriate intervals specified in the Plan, but in no case less than once a year. Such evaluations shall provide:

(1) Areas contributing to a stormwater discharge associated with industrial activity shall be visually inspected for evidence of, or the potential for, pollutants entering the drainage system. Measures to reduce pollutant loadings shall be evaluated to determine whether they are adequate and properly implemented in accordance with the terms of this permit or whether additional control measures are needed. Structural stormwater management measures, sediment and erosion control measures, and other structural pollution prevention measures identified in the Plan shall be observed to ensure that they are operating correctly. A visual inspection of equipment needed to implement the Plan, such as spill response equipment, shall be made.

(2) Based on the results of the inspection, the description of potential pollutant sources identified in the Plan in accordance with paragraph VII.C.1.a.(5) of this section and pollution prevention measures and

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controls identified in the Plan in accordance with paragraph VII.C.1.b of this section shall be revised as appropriate within two weeks of such inspection and shall provide for implementation of any changes to the Plan in a timely manner, but in no case more than twelve weeks after the inspection.

(3) A report summarizing the scope of the inspection, personnel making the inspection, the date(s) of the inspection, observations relating to the implementation of the Plan and actions taken shall be made and retained as part of the Plan. The report shall identify any incidents of non-compliance, and corrective actions taken. Where a report does not identify any incidents of non-compliance, the report shall contain a certification that the facility is in compliance with the Plan and this permit. The report shall be signed in accordance with paragraph VII.A.6 of this section.

d. Consistency with other plans. The Plan may reference the existence of other plans for Spill Prevention Control and Countermeasure (SPCC), plans developed for the facility under section 311 of the CWA or BMP Programs otherwise required by an NPDES permit for the facility if such requirement is incorporated into the Plan.

VIII. OTHER SPECIFIC CONDITIONS

A. Specific Conditions Applicable to All Permits

1. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.), F.S., applicable portions of reports that must be submitted under this permit shall be signed and sealed by a State-registered professional engineer or professional geologist, as appropriate. *[62-620.310(4)]*

2. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Department's Wastewater Management Program in Tallahassee, are made a part hereof.

3. This permit satisfies Wastewater Management Program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
(1) One hundred micrograms per liter,
(2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2, 4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol; and one milligram per liter for antimony, or
(3) Five times the maximum concentration value reported for that pollutant in the permit application; or

b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
(1) Five hundred micrograms per liter,
(2) One milligram per liter for antimony, or
(3) Ten times the maximum concentration value reported for that pollutant in the permit application.

[62-620.625(1)]

C. Duty to Reapply

1. The permittee is not authorized to release wastewater into the CCS after the expiration date of this permit, unless:

a. the permittee has applied for renewal of this permit at least 180 days before the expiration date (**Month, Day, Year**) using the appropriate forms listed in Rule 62-620.910, F.A.C., and in the manner established in

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the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.; or

b. the permittee has made complete the application for renewal of this permit before the permit expiration date.

[62-620.335(1)-(4)]

2. When publishing Notice of Draft and Notice of Intent in accordance with Rules 62-110.106 and 62-620.550, F.A.C., the permittee shall publish the notice at its expense in a newspaper of general circulation in the county or counties in which the activity is to take place either

   a. Within thirty days after the permittee has received a notice; or

   b. Within thirty days after final agency action.

   Failure to publish a notice is a violation of this permit.

D. Reopener Clauses

1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the CWA, as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, Department approved changes in water quality standards, EPA established Total Maximum Daily Loads (TMDLs), or other information show a need for a different limitation, monitoring requirement, or more stringent requirements.

3. The Department or EPA may develop a TMDL during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

4. The permittee and the Department entered into a Consent Order (OGC File #16-0241) on June 20, 2016. The Department may revise the permit to include certain provisions of the Consent Order upon its completion.

E. Impoundment Design, Construction, Operation, and Maintenance

1. All impoundments used to hold or treat wastewater and stormwater, including the CCS, shall be designed, constructed, operated, and maintained to prevent the discharge of pollutants to waters of the State, except as authorized under this permit.

2. Design, construction, operation, and maintenance of any impoundment shall be in accordance with all relevant State and Federal regulations and shall be certified by a qualified, State-registered professional engineer and permitted and inspected by the appropriate agency prior to use. When practicable, piezometers or other instrumentation shall be installed as a means to aid monitoring of impoundment integrity.

3. In addition to other regular maintenance activities conduction for the CCS, which for the purposes of this section is considered an impoundment, the perimeter berms and slopes shall be maintained to protect the structural

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integrity. This may include removal of trees greater than 4 inches in diameter. Vegetation and materials shall be handled and managed in accordance to the Best Management Practices Plan in Section VII of this permit.

F. Impoundment Inspections

1. The CCS periphery including the three small dams (Hotel 2, Turtle Point Canal, and the Cellular Cofferdam) shall be inspected above and below the surface waterline for the entire perimeter at a minimum of once every five years by an independent qualified, State-registered professional engineer. The three dams and all other aspects of the perimeter impoundments shall be inspected annually by a qualified, State-registered professional engineer. The term qualified means having successfully completed the Mine Safety and Health Administration Qualification for Impoundment Inspection course in addition to the Annual Retraining for Impoundment Qualification, or equivalent Qualifications. Additional inspections by qualified personnel shall be done within 7 days after large or extended rain events (i.e., 10-year, 24-hour precipitation event).

2. Inspections shall, at a minimum, include observations of dams, including the three dams (Hotel 2, Turtle Point Canal and the Cellular Cofferdam) of the CCS, dikes and toe areas for erosion, corrosion, cracks or bulges, seepage, wet or soft soil, changes in geometry, the depth and elevation of the impounded water, sediment or slurry, freeboard, changes in vegetation such as overly lush, dead or unnaturally tilted vegetation, and any other changes which may indicate a potential compromise to impoundment integrity.

   To monitor function of the cathodic protection system, suggested operation and maintenance practices described in the Operation and Maintenance Manual accompanying these devices shall be followed.

   In addition, the CCS shall be monitored in the months of April and August of each year to determine its thermal efficiency. The thermal efficiency in the CCS shall be calculated as described in the Turkey Point Cooling Canal System Thermal Efficiency Plan. If the permittee fails to achieve a minimum annual average of 70 percent, the permittee shall, within 30 days of discovering that the thermal efficiency is below the threshold, commence actions prescribed in the Turkey Point Cooling Canal System Thermal Efficiency Plan. If the permittee fails to reach the threshold by the following annual report, within 30 days, the permittee shall notify the Tallahassee Wastewater Management Program of additional measures to be taken, and a timeframe for achieving the threshold. The Turkey Point Cooling Canal System Thermal Efficiency Plan shall be updated to include the additional measures.

   The findings of each inspection including thermal efficiency, shall be documented in a written annual inspection report as described in permit condition VIII.G.1 below.

3. Remediation Measures. Within 24 hours of discovering changes that indicate a potential compromise to the structural integrity or the efficient operation of the CCS, the permittee shall begin procedures to remediate the problem. Adherence to the six components of the Turkey Point Cooling Canal System Thermal Efficiency Plan dated December 14, 2016, shall be incorporated into the facility's best management practices.

4. Within 5 days of discovering any changes in the CCS that indicate a potential compromise to the structural integrity or operation, the permittee must notify the Department in writing describing the findings of the inspection, corrective measures taken since discovery of the change, other planned corrective measures and the expected outcomes. Failure to do so will be a violation of this permit.

5. Other issues which may have long term impacts on impoundment integrity, such as trees growing on the CCS perimeter impoundment or banks or vegetation blocking canals or spillways, shall be cleared within a timely manner to ensure operational integrity, but no later than 6 months from first observation. In addition, the CCS impoundment shall be maintained to prevent the growth, accumulation, or spread of any plant species.

6. During routine operational and maintenance activities around the CCS, periodic observation of the perimeter should continue reporting noted defects.

G. Reporting and Recordkeeping Requirements

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1. In accordance with schedule item VI.4 the permittee shall submit an annual report of all impoundment inspections and maintenance activities, including corrective actions made in response to inspections, summarizing findings of all monitoring activities including the annual thermal efficiency evaluation of the CCS, remediation measures pertaining to the structural integrity, design, construction, and operation and maintenance of the CCS, and all other activities undertaken to repair or maintain the CCS and other impoundments.

2. In accordance with Section 403.077, F.S., unauthorized releases or spills reportable to the StateWatch Office pursuant to permit condition IX.20 shall also be reported to the Department within 24 hours from the time the permittee becomes aware of the discharge. The permittee shall provide to the Department information reported to the State Watch Office. Notice of unauthorized releases or spills may be provided to the Department through the Department's Public Notice of Pollution web page at https://floridadep.gov/pollutionnotice.

   a. If, after providing notice pursuant to paragraph (2) above, the permittee determines that a reportable unauthorized release or spill did not occur or that an amendment to the notice is warranted, the permittee may submit a letter to the Department documenting such determination.

   b. If, after providing notice pursuant to paragraph (2) above, the permittee discovers that a reportable unauthorized release or spill has migrated outside the property boundaries of the installation, the permittee must provide an additional notice to the Department that the release has migrated outside the property boundaries within 24 hours after its discovery of the migration outside of the property boundaries.

H. Specific Conditions Related to Preservation of State Historical Resources

1. If prehistoric or historic artifacts, such as pottery or ceramics, projectile points, dugout canoes, metal implements, historic building materials, or any other physical remains that could be associated with Native American, early European, or American settlement are discovered at any time within the project site area, the permittee shall immediately notify the Florida Department of State, Division of Historical Resources, Compliance Review Section at (850) 245-6333, to determine appropriate action.

2. In the event that unmarked human remains are encountered during permitted activities, all work shall stop immediately and the proper authorities notified in accordance with Section 872.05, Florida Statutes.

I. Other Noncompliance Reporting Requirements

1. In accordance with Section 403.077, F.S., unauthorized releases or spills reportable to the State Watch Office pursuant to Permit Condition IX.20.b.1. shall also be reported to the Department within 24 hours from the time the permittee becomes aware of the discharge. The permittee shall provide to the Department information reported to the State Watch Office. Notice of unauthorized releases or spills may be provided to the Department through the Department's Public Notice of Pollution web page at https://floridadep.gov/pollutionnotice.

   a. If, after providing notice pursuant to paragraph 1 above, the permittee determines that a reportable unauthorized release or spill did not occur or that an amendment to the notice is warranted, the permittee may submit additional notice to the Department documenting such determination.
   b. If, after providing notice pursuant to paragraph 1 above, the permittee discovers that a reportable unauthorized release or spill has migrated outside the property boundaries of the installation, the permittee must provide an additional notice to the Department that the release has migrated outside the property boundaries within 24 hours after its discovery of the migration outside of the property boundaries.

[62-620.100(3)] [403.077, F.S.]

IX. GENERAL CONDITIONS

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1)]*

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2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2)]*

3. As provided in Section 403.087(7), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3)]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4)]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5)]*

6. If the permittee plans to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6)]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7)]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8)]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;

   b. Have access to and copy any records that shall be kept under the conditions of this permit;

   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and

   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

   [62-620.610(9)]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, F.S., or Rule 62-

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620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10)]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11)]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12)]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13)]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. *[62-620.610(14)]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility or activity and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15)]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rule 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with subsection 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16)]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

    a. A description of the anticipated noncompliance;

    b. The period of the anticipated noncompliance, including dates and times; and

    c. Steps being taken to prevent future occurrence of the noncompliance.

    [62-620.610(17)]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246 and Chapters 62-160, 62-601, and 62-610, F.A.C., and 40 CFR 136, as appropriate.

    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a DMR, DEP Form 62-620.910(10), or as specified elsewhere in the permit.

    b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

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d. Except as specifically provided in Rule 62-160.300, F.A.C., any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health Environmental Laboratory Certification Program (DOH ELCP). Such certification shall be for the matrix, test method and analyte(s) being measured to comply with this permit.

e. Field activities including on-site tests and sample collection shall follow the applicable standard operating procedures described in DEP-SOP-001/01 adopted by reference in Chapter 62-160, F.A.C.

f. Alternate field procedures and laboratory methods may be used where they have been approved in accordance with Rules 62-160.220, and 62-160.330, F.A.C.

[62-620.610(18)]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19)]*

20. The permittee shall report to the Department's Southeast District Office any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

    a. The following shall be included as information which must be reported within 24 hours under this condition:
        (1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
        (2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
        (3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
        (4) Any unauthorized discharge to surface or groundwaters.

    b. Oral reports as required by this subsection shall be provided as follows:
        (1) For unauthorized releases or spills of treated or untreated wastewater reported pursuant to subparagraph 20(a).4. that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the STATE WATCH POINT OFFICE TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Watch Point:
            (a) Name, address, and telephone number of person reporting;
            (b) Name, address, and telephone number of permittee or responsible person for the discharge;
            (c) Date and time of the discharge and status of discharge (ongoing or ceased);
            (d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
            (e) Estimated amount of the discharge;
            (f) Location or address of the discharge;
            (g) Source and cause of the discharge;
            (h) Whether the discharge was contained on-site, and cleanup actions taken to date;
            (i) Description of area affected by the discharge, including name of water body affected, if any; and
            (j) Other persons or agencies contacted.
        (2) Oral reports, not otherwise required to be provided pursuant to subparagraph 20.b.1 above, shall be provided to the Department's Southeast District Office within 24 hours from the time the permittee becomes aware of the circumstances.

    c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Southeast District Office shall waive the written report.

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[62-620.610(20)]

21. The permittee shall report all instances of noncompliance not reported under Permit Conditions IX. 17, 18 or 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Permit Condition IX.20 of this permit. *[62-620.610(21)]*

22. Bypass Provisions.

    a. "Bypass" means the intentional diversion of waste streams from any portion of a treatment works.

    b. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
       (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
       (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
       (3) The permittee submitted notices as required under Permit Condition IX.22.c. of this permit.

    c. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Permit Condition IX.20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

    d. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Permit Condition IX. 22.b.1 through 3 of this permit.

    e. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of Permit Condition IX.22.a. through c. of this permit.

    [62-620.610(22)]

23. Upset Provisions.

    a. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based effluent limitations because of factors beyond the reasonable control of the permittee.
       (1) An upset does not include noncompliance caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, careless or improper operation.
       (2) An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of upset provisions of Rule 62-620.610, F.A.C., are met.

    b. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
       (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
       (2) The permitted facility was at the time being properly operated;
       (3) The permittee submitted notice of the upset as required in Permit Condition IX.20. of this permit; and
       (4) The permittee complied with any remedial measures required under Permit Condition IX.20. of this permit.

    c. In any enforcement proceeding, the burden of proof for establishing the occurrence of an upset rests with the permittee.

    d. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.

    [62-620.610(23)]

Executed in Tallahassee, Florida.

PROPOSED

PERMITTEE: Florida Power & Light Company (FPL)
FACILITY: Turkey Point Power Plant

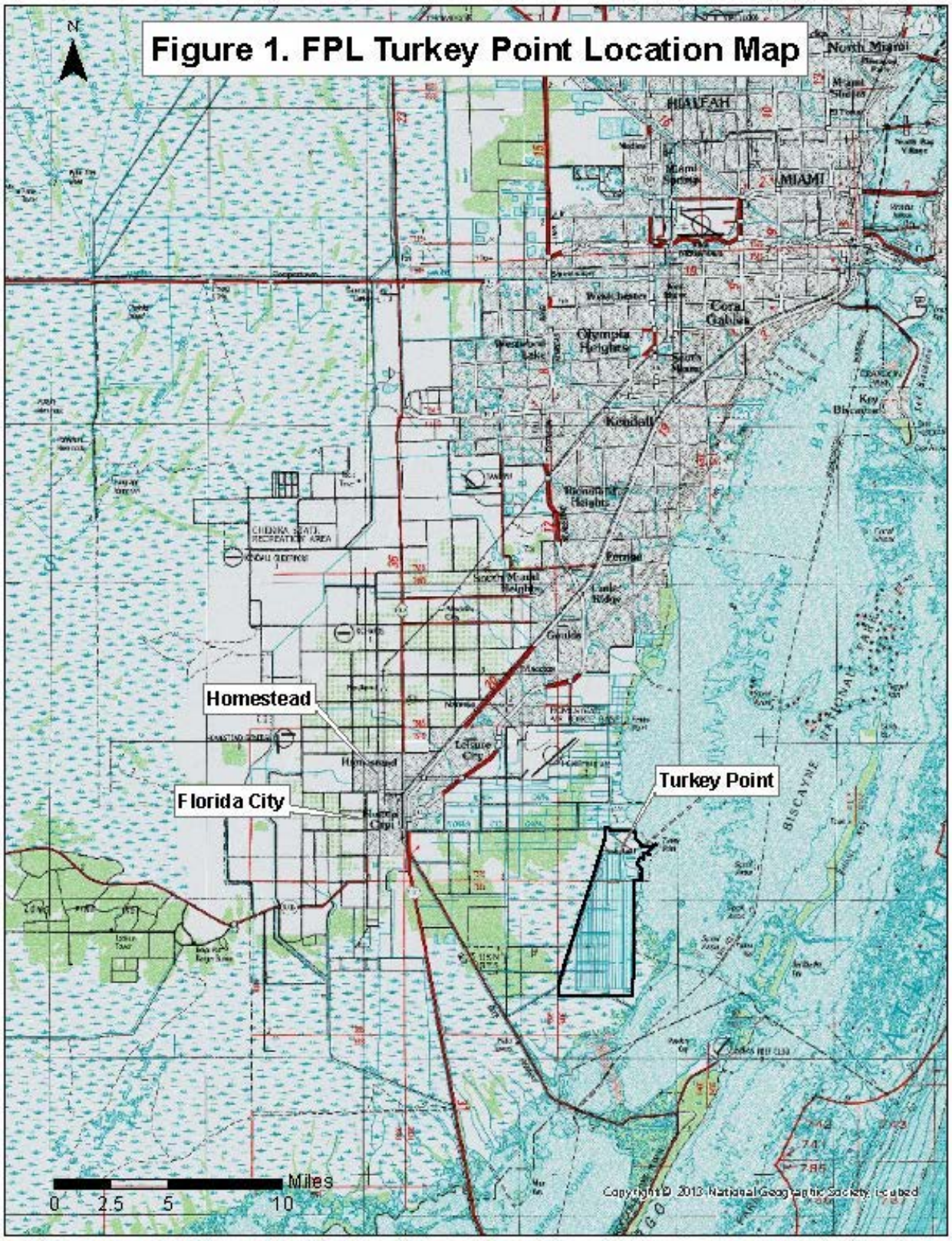
PERMIT NUMBER: FL0001562 (Major)
EXPIRATION DATE:

STATE OF FLORIDA DEPARTMENTOF
ENVIRONMENTAL PROTECTION

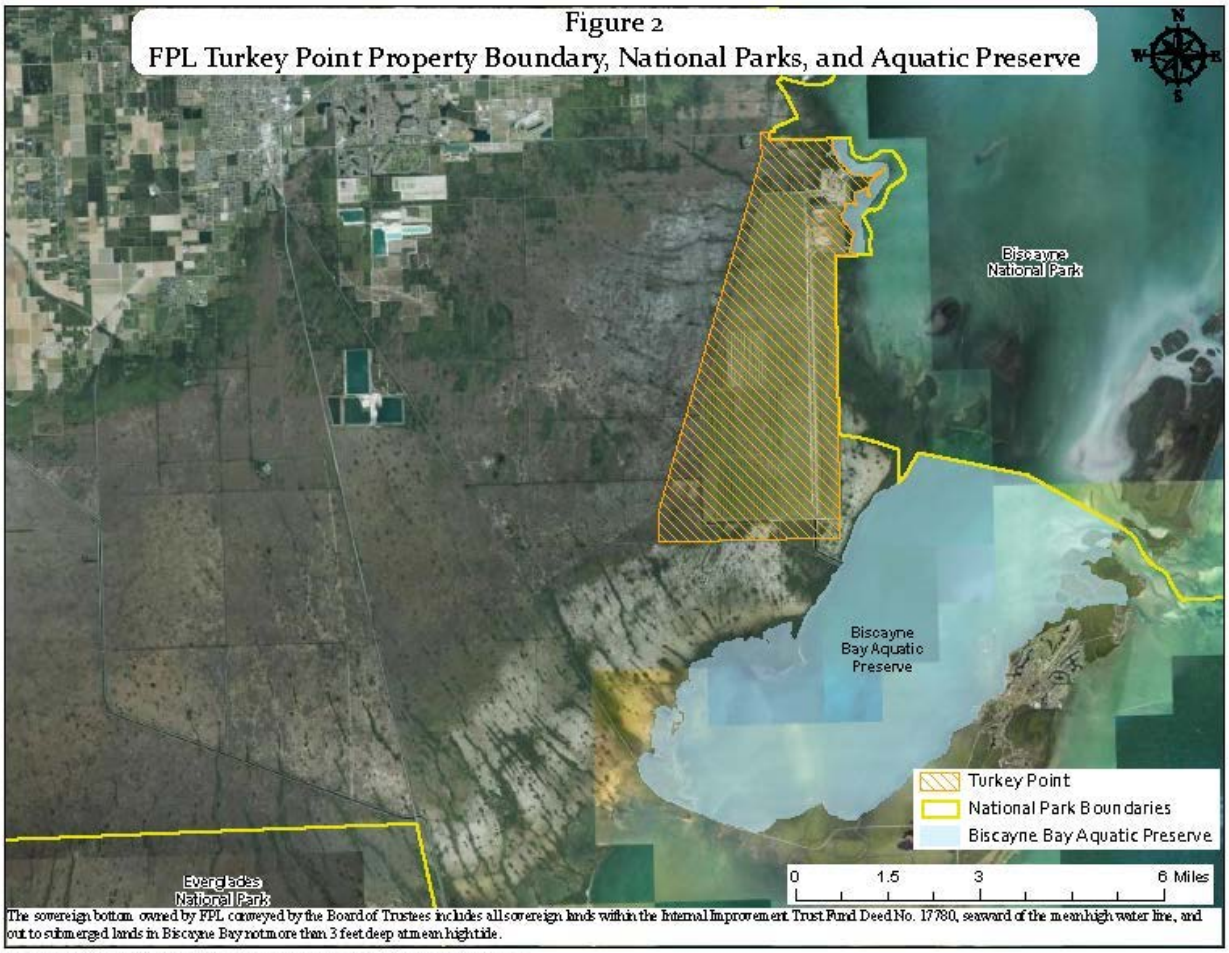
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Benjamin M. Melnick
Director
Division of Water Resource Management

PROPOSED

PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
FACILITY: Turkey Point Power Plant EXPIRATION DATE:



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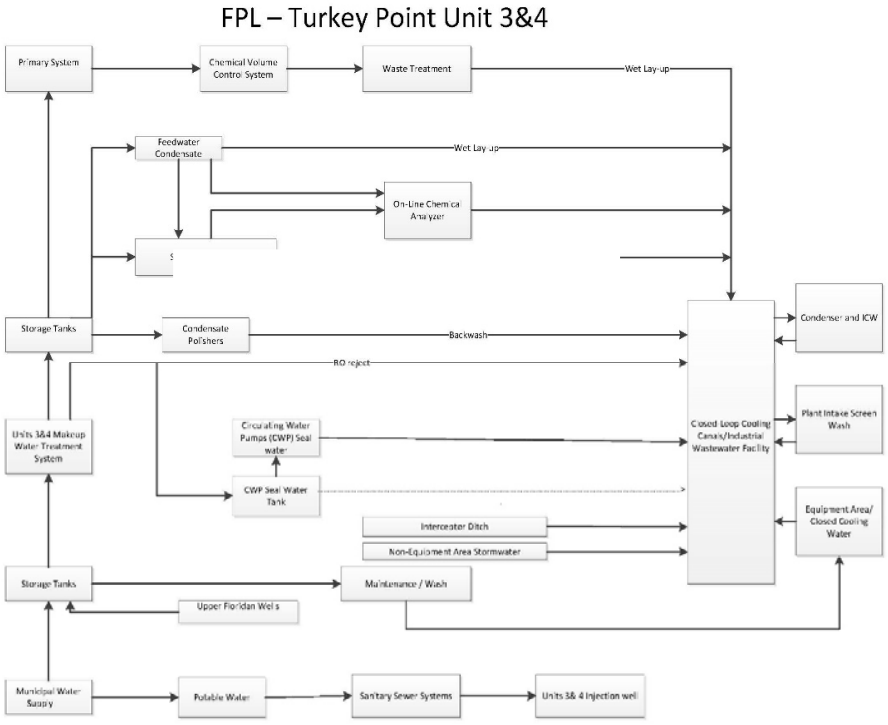
PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
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Figure 3
FPL Turkey Point Property Boundary

PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
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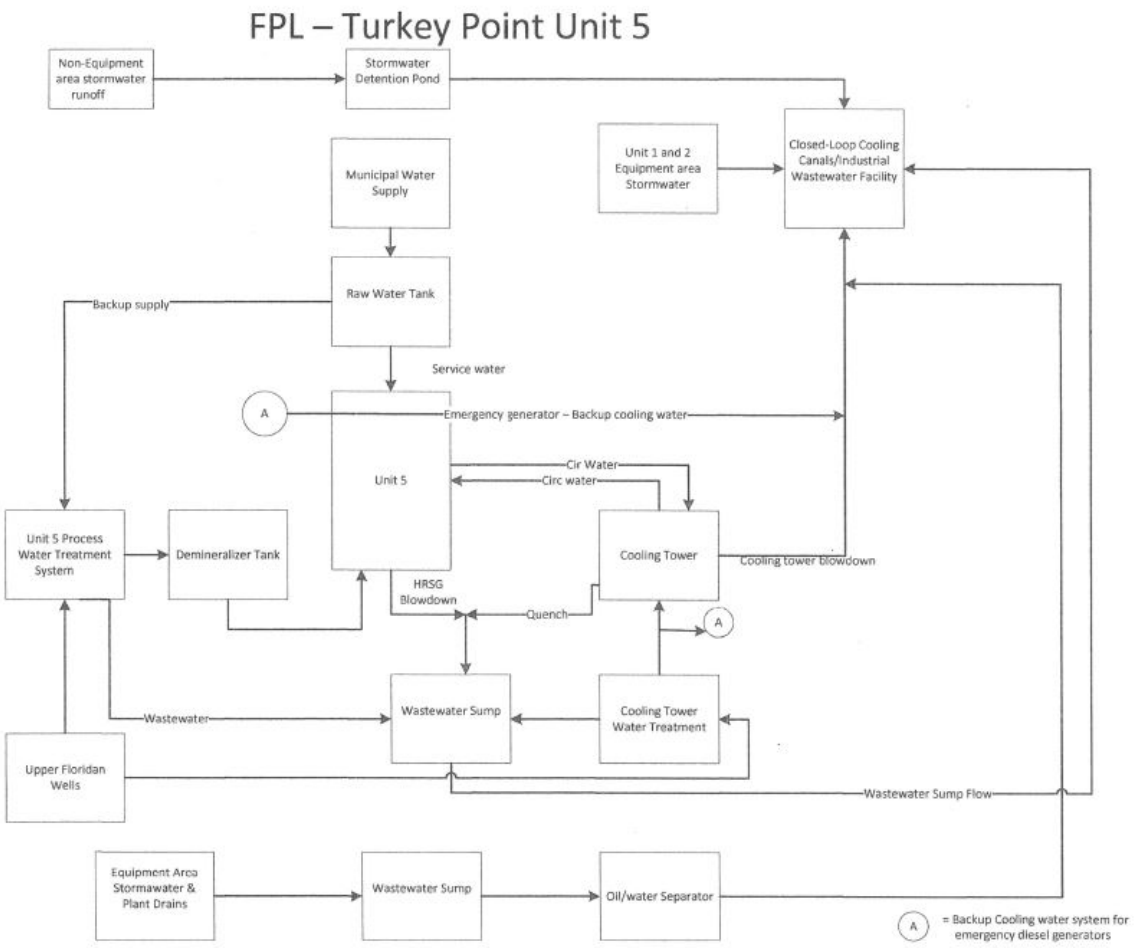
Figure 4. FPL Turkey Point Power Plant Units 3 & 4 Flow Diagram



PROPOSED

PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
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Figure 5. FPL Turkey Point Power Plant Unit 5 Flow Diagram



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Figure 6. FPL Turkey Point Power Plant Groundwater, Surface Water, and Porewater Monitoring Locations

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PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
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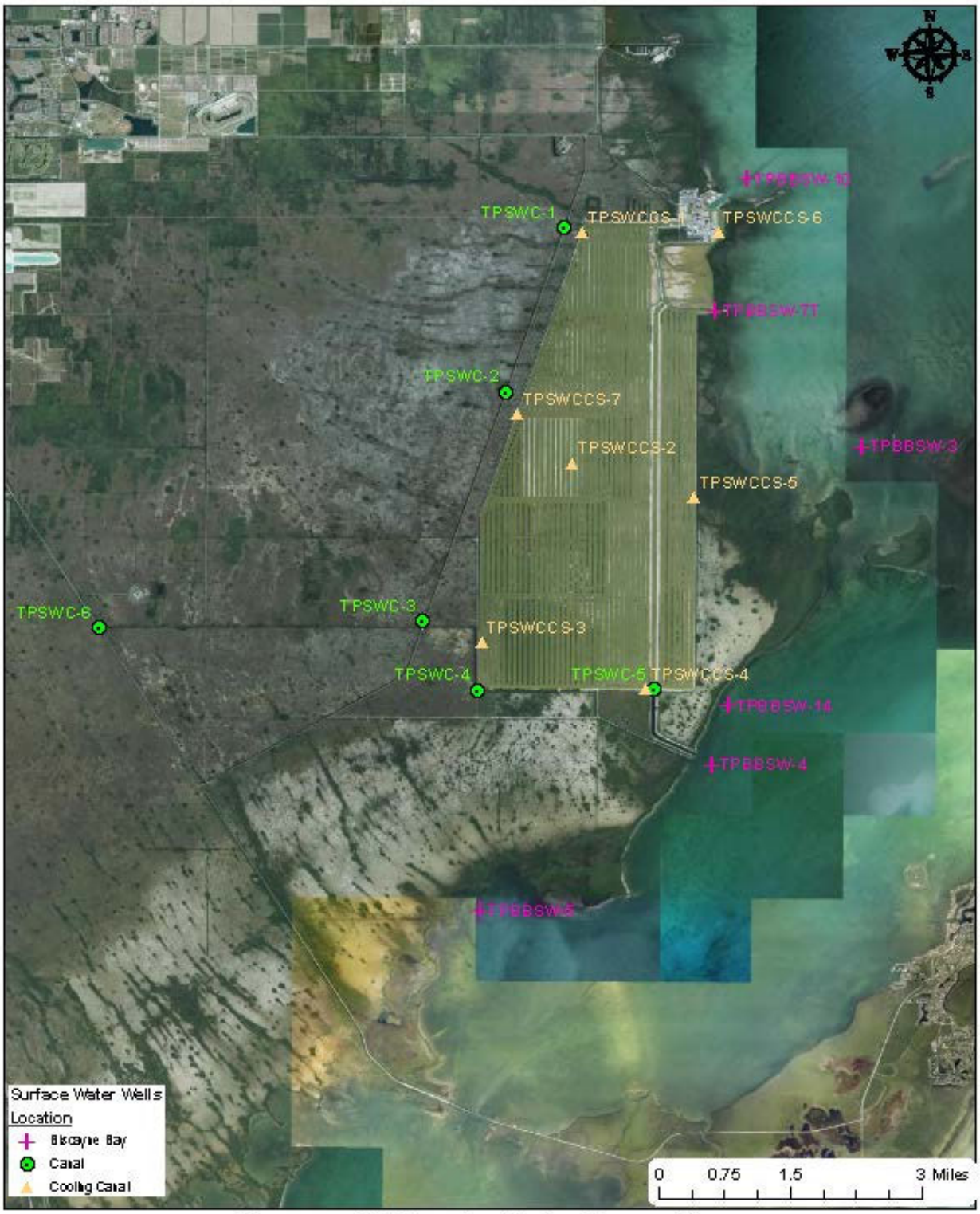
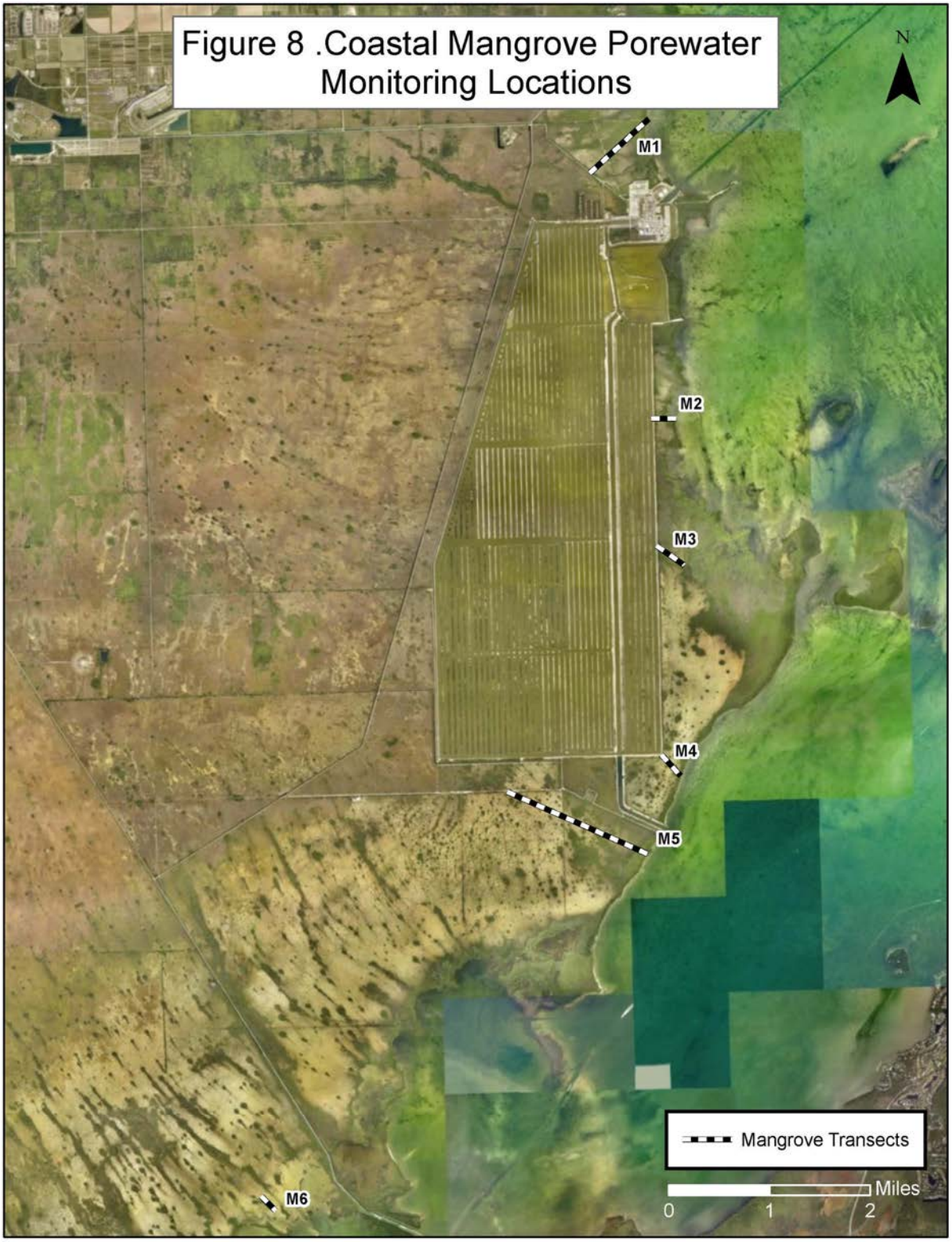


Figure 7. FPL Turkey Point Power Plant
Surface Water Monitoring Locations

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PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
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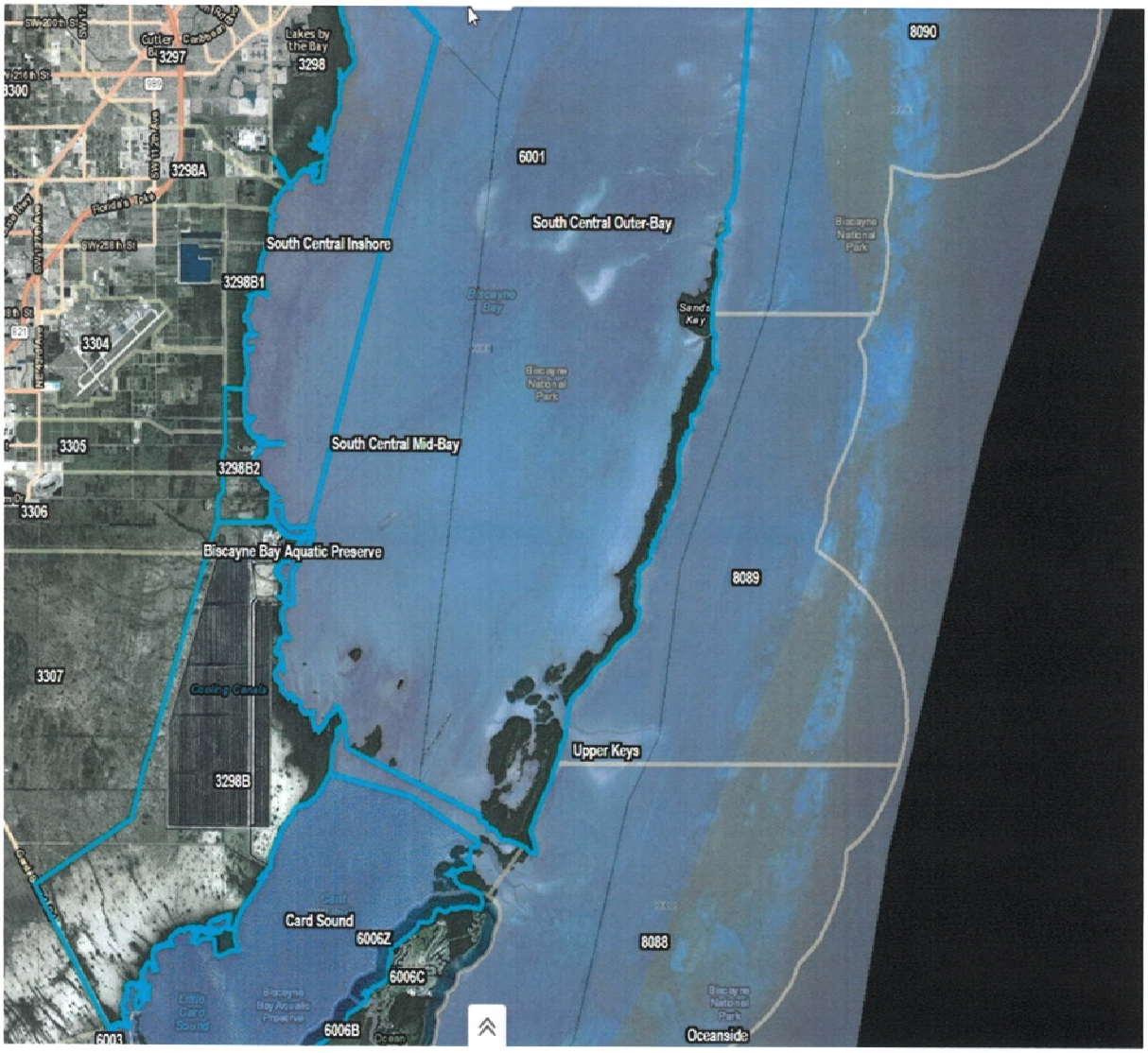


PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
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PERMITTEE: Florida Power & Light Company (FPL) PERMIT NUMBER: FL0001562 (Major)
FACILITY: Turkey Point Power Plant EXPIRATION DATE:

Figure 10. South Central and Card Sound Bay Segments



FACT SHEET
FOR
STATE OF FLORIDA INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMIT NUMBER: FL0001562 (Major)

NAME OF PERMITTEE: Florida Power & Light Company (FPL)

FACILITY NAME: Turkey Point Power Plant

FACILITY LOCATION: 9760 SW 344th St, Florida City, Florida 33035
Miami-Dade County

PERMIT WRITERS: Frank Wall, Engineering Specialist IV

Allan Stodghill, P.G., Professional Geologist II

Marc Harris, P.E., Program Administrator

Addendum to Factsheet – The public comment period for the Notice of Draft began on January 15, 2019. During the comment period, the Department received requests to extend the comment period beyond 30 days. A public notice announcing a public meeting was published in the Miami Herald on April 4, 2019. The public meeting was held on May 7, 2019, in Homestead. During the meeting the public had the opportunity to discuss their concerns directly with the Department and FPL representatives. The Department accepted additional comments from the public on the day of the meeting until close of business May 21, 2019. As a result of the comments received and the input from the public meeting, the draft permit was revised as follows:

1. *The facility description section of the permit was updated to more accurately reflect facility operations and surrounding locations along the facility boundaries. Figure 2 was updated with a map showing the boundaries of Biscayne National Park, Biscayne Bay Aquatic Preserve, and Everglades National Park. Figure 3 was replaced with a map showing the boundaries of the Turkey Point facility. Under the wastewater treatment section, the sentence referring to discharges from the facility to surface waters of the State was removed to provide clarity to authorized discharges explicitly expressed in the permit.*

2. *A statement was added to the reuse or disposal groundwater discharge section of the permit regarding Miami-Dade County's regulatory authority under the County's Home Charter Rule. Minor descriptive changes to this section were also provided for clarification.*

3. *Monitoring group D-02A was revised from surface water to porewater in the reuse or disposal section and permit condition II.C.1. The groundwater monitoring group G-001 descriptor "outfall" was replaced with "series".*

4. *Permit condition I.1. The condition was expanded to include reference to Rule 62-520.420, F.A.C., adjacent groundwaters, and compliance schedule items.*

5. *Footnote 2. The footnote was revised by removal of "remedial" and "for achieving compliance with this condition of" as they are not indicative of the requirements of paragraphs 19 and 21 of Consent Order 16-0241.*

6. *Permit condition I.4. The table was expanded to include monitoring for sulfide. Table note "*" well references were revised from TPGW-1 and TPGW-18 to TPGW-L3-18 and TPGW-L5-18. Table note "**" was expanded to clarify sampling frequency and sample collection. Reference to table note "**" was included for the specific conductance. Additionally, the monitoring frequency for temperature was revised from hourly to quarterly consistent with the clarification to note "**".*

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7. *New permit condition I.5. The condition was added to the permit which identifies monitoring wells TPGW- 1, 4, 5, 6, 17, 18, and 19 used to assist in the determination of the extent of retraction of the hypersaline plume.*

8. *Permit condition I.7. For clarification, the parameter "N" was revised to Nitrite plus Nitrate, Total (as N). The condition was expanded requiring the facility to implement Department-approved corrective action to address water quality violation and/or impacts within a timetable provided by the Department.*

9. *New permit condition II.A.2. The permit condition prohibits the facility from causing or contributing to a violation of the surface water quality standards or criteria in Rule 62-302, F.A.C.*

10. *Permit condition II.A.4 (Formerly II.A.3). The table was updated to require all parameters to be monitored at SWD-8, SWD-9, SWD-10, SWD-11, and SWD-12, where applicable. Sample type was updated for all instances of Instantaneous to In situ based on comments provided by the facility. Total sodium was revised to total recoverable sodium. For NPDES permitting the two may be used interchangeably.*

11. *Permit condition II.B.1. Sample type was updated for temperature from Instantaneous to In situ based on comments provided by the facility. Total sodium was revised to total recoverable sodium. For NPDES permitting the two may be used interchangeably. Monitoring site OUI-2 was removed from salinity as the value is capture in the calculation provided by CAL-1.*

12. *Permit condition II.B.3. The permit condition was expanded requiring automated hourly data and analytical results from existing individual stations be made available via FPL's EDMS. Reference to Biscayne Bay is not applicable to this permit condition and was therefore removed. The monthly requirement to compile and create an average was revised to quarterly.*

13. *Permit condition II.B.5. The permit condition was revised to require submittal of copies of comments or findings based on report and data submittals reviewed by other agencies to the Department upon request.*

14. *Permit condition II.C.2. Total sodium and total calcium were revised to total recoverable sodium and calcium. For NPDES permitting the two may be used interchangeably. Fluid density units were revised from g/cm3 to g/ml as the two are identical.*

15. *Permit condition II.D.1. Sentence 1 was revised to include reference to a "Department-approved methodology".*

16. *Permit condition II.D.8. This condition was revised to include a new subsection b regarding the formation of nuisances, and reference to Rule 62-302.500(1), F.A.C.*

17. *Permit condition II.D.10. The introductory sentence was revised to include, "Discharge of" and "this requirement is not applicable to", for the purpose of additional clarification.*

18. *Permit condition II.D.15 and footnote 6. The facility was first authorized approval to trial use Optisperse PWR6600 for six months in August of 2018. Additional six-month trials were approved following the initial request. Based on the information provided, Optisperse was added to the approved chemical list of permit condition II.D.15. The facility also indicated that it was no longer trialing anodamine. Based on these changes, footnote 6 is no longer applicable, and hence was removed from the proposed permit.*

19. *Permit condition II.D.19.a. The condition was revised to include reference to Waters of the State.*

20. *Permit condition III.4. The permit condition was expanded requiring vegetation and materials be handled and managed in accordance with the Best Management Practices Plan in Section VII of the permit.*

21. *Schedule item VI.4. The annual nutrient monitoring summary report submittal requirement to begin the third year following permit issuance was removed, and the requirement that it be based on 24 months of data was revised to 12 months of data.*

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22. *New schedule items VI.8-10. The new schedule items refer to the hypersaline plume management compliance requirements.*

23. *New permit condition VII.B.3.c.(1)(h). This is a new required component of the waste minimization assessment (WMA) of the Best Management Practices Plan that requires implementation of the Turkey Point CCS Nutrient Management Plan (September 16, 2016), including submittal of annual progress reports.*

24. *Permit condition VIII.E.3. The permit condition was expanded requiring vegetation and materials be handled and managed in accordance with the Best Management Practices Plan in Section VII of the permit.*

25. *Permit condition VIII.F.1. The sentence, "All impoundments other than the CCS shall be inspected at least monthly by qualified personnel.", was removed as the remaining portions of the permit condition provide coverage for the impoundment inspections. The facility indicated that no other impoundments exist at the facility.*

26. *Permit condition VIII.F.5. The permit condition regarding impoundment inspections was expanded requiring maintenance to prevent the growth, accumulation, or spread of any plant species that impact structural integrity of the impoundments. The timeframe was revised to be timely, but no later than 6 months.*

27. *New Section VIII.I. A new standard permit condition VIII.I.1 was added to the permit requiring notification of unauthorized releases or spills be provided to the Department through the Department's Public Notice of Pollution web page.*

28. *The compliance submittal month was revised from November to August 31st throughout the permit.*

Changes as described above to the permit are hereby noted as corresponding changes to the Fact Sheet where applicable.

At the request of the facility, updates and clarifications to the Fact Sheet are identified by italics and underline, while deletions are identified by strikethrough as shown below.

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Abbreviations and Acronyms

AADF	Annual Average Daily Flow
AGM	Annual geometric mean
BPJ	Best Professional Judgement
CCS	Cooling Canal System
CO	Consent Order
Deg F	Degrees Fahrenheit
EPA	United States Environmental Protection Agency
Ft	Feet
F.A.C.	Florida Administrative Code
FPL	Florida Power & Light Company
F.S.	Florida Statutes
g/cm^3	Grams per cubic centimeter
ICW	Intake Cooling Water
MW	Megawatts
ug/L	Microgram per liter
umhos/cm	Micromhos per centimeter
mg/L	Milligrams per liter
MGD	Million Gallons per Day
NPDES	National Pollutant Discharge Elimination System
NTU	Nephelometric Turbidity Unit
NAICS	North American Industry Classification System
NAVD	North American Vertical Datum
NOV	Notice of Violation
OGC	Office of General Counsel
OTCW	Once-through Cooling Water
OFW	Outstanding Florida Water
pCi/L	Picocuries per liter
PCU	Platinum-Cobalt Unit
PSU	Practical Salinity Unit
P.E.	Professional Engineer
P.G.	Professional Geologist
SFWMD	South Florida Water Management District
SIC	Standard Industrial Classification
s.u.	Standard Units
TDS	Total Dissolved Solids
TMDL	Total Maximum Daily Load
USGS	United States Geological Survey

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BACKGROUND

1. CHRONOLOGY OF APPLICATION

File Number:	FL0001562-012-IW1N
Application Submittal Date:	October 22, 2009
Additional Information:	March 12th, June 1st, August 16th, September 16th & December 13th, 2010; September 30th, 2016; February 10th & 22nd, April 24th, May 5th, August 16th & 29th & October 16th, 2017; August 3rd, September 11th & 14th, October 29th, November 5th, December 4th, 2018, and other dates.
Notice of Draft:	January 2, 2019 (issued); January 15, 2019 (published)
Public Meeting:	April 4, 2019 (published); May 7, 2019 (public meeting); May 21, 2019 (comment period closed)

2. FACILITY DESCRIPTION

Standard Industrial Classification (SIC) Code: 4911 - Electrical Generation.

316(b): The facility does not have any cooling water intake structures, and therefore, is not subject to Section 316(b) of the Clean Water Act.

North American Industry Classification System (NAICS): 221112 - Fossil Fuel Electric Power Generation, 221113 – Nuclear Electric Power Generation.

Existing Cooling Canal System Permitted Capacity: 2763 Million Gallons per Day (MGD) Annual Average Daily Flow (AADF)

Proposed Increase in Permitted Capacity: No increase

Proposed Total Permitted Capacity: 2763 MGD AADF

The Turkey Point facility, which began operation in 1967, is located on approximately 11,000 acres in unincorporated southeast Miami-Dade County about 25 miles south of Miami and about nine miles east of Florida City and Homestead (See Figure 1, FPL Turkey Point Location Map). Biscayne National Park, established in 1980, lies adjacent to eastern portions of the facility. The Biscayne Bay Aquatic Preserve, established in 1974, is southeast of the facility. Everglades National Park, established in 1934, is to the south and west (see Figure 2, Turkey Point Power Plant, National Parks, and Aquatic Preserve).

West of the facility are the South Florida Water Management District (SFWMD) L-31E Canal, the historic C-106 Canal (Model Lands North Canal), and the historic C-107 Canal (Model Lands South Canal). Southeast of the facility is the Card Sound *Discharge* Canal and southwest and south is the SFWMD S-20 Discharge Canal. The remnant canals at Turtle Point and the Barge Basin are located east northeast and northeast of the facility, respectively (see Figure 3, Turkey Point Power Plant Internal Outfall and Dam Structures and Adjacent Canals).

The facility consists of three electrical generating units: two nuclear units (Units 3 and 4) and one natural gas-fired combined cycle unit (Unit 5). Units 3, 4, and 5 began commercial operation in 1972, 1973, and 2007, respectively. Units 3 and 4 each have a nominal capacity of 815 Megawatts (MW) and Unit 5 has a nominal capacity of 1209 MW. Units 3, 4 and 5 are also regulated under the Florida Electrical Power Plant Siting Act (License No. PA03-045).

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FPL owns and operates a recirculating cooling canal system (CCS) at the facility *that began permitted operation in 1973*. The CCS provides a heat removal function for the cooling water from Units 3 and 4. Unit 5 dissipates heat through cooling tower cells. The heated water generated by operation of Units 3 and 4 is released to the recirculating CCS and returned to Units 3 and 4. The temperature of the water entering Units 3 and 4 is regulated by the U.S. Nuclear Regulatory Commission under the Atomic Energy Act. Groundwater withdrawals from the Floridan aquifer is the source of cooling water for Unit 5, and is authorized under License No. PA03-045. Groundwater from the Floridan aquifer is also used as makeup water to help offset evaporation within the CCS.

The facility, as originally designed and constructed, included a once-through cooling water (OTCW) system (i.e., point source discharge of heated wastewater to surface waters). The facility obtained cooling water by drawing surface water from an intake channel connected to Biscayne Bay, and discharged the heated wastewater into Biscayne Bay and Card Sound through a series of discharge canals. FPL was required to construct the CCS to satisfy a 1971 consent judgment with the U.S. Department of Justice. The judgement required the permitting, construction, operation, and maintenance of the CCS as a recirculating cooling water system (i.e., no point source discharges of heated wastewater to surface waters). In addition, the judgement allowed FPL to directly discharge CCS water through the Card Sound *Discharge* Canal to Card Sound, provided the discharge met the stipulated requirements in the judgement. This allowance was to prevent the excessive concentration of salt in the CCS water.

In 1972, the U.S. Atomic Energy Commission prepared an environmental impact statement (EIS) with respect to the construction of the cooling canal system. The EIS indicated that water from the CCS would discharge to groundwater and that some of that groundwater could seep into adjacent surface waters (Biscayne Bay and Card Sound). The EIS acknowledged the potential for minimal adverse impacts on flora (red mangroves) and fauna (shallow benthic communities). The approach to groundwater seepage set forth ~~in the draft permit is~~ *in the EIS was* to monitor the effects of groundwater seepage and address any adverse environmental impacts that may develop.

The construction of the CCS *began in 1972* ~~was completed in August 1973~~*. Construction was completed and operations permitted in 1973*. ~~The CCS became fully operational in 1978 and~~ *The CCS* occupies an area approximately 2 miles wide by 5 miles long. This area includes a network of 168 miles of earthen canals covering approximately 6,900 acres of which 4,370 acres are water surface. The circulation route from the plant discharge to plant intake is 13.2 miles and takes approximately 44 hours to complete. The CCS canals are excavated into the native rock and the underlying surficial aquifer, which is *part of* the Biscayne aquifer.

The CCS perimeter berms were constructed using structural road base material and excavated rock fill. Berm widths around the perimeter of the CCS range from about 25 feet to over 100 feet, with an average width of about 50 feet. Interior berms separating the canal sections are primarily covered with deposited excavated soils from the CCS canals.

The perimeter includes three small, manmade dams: two earthen dams each with an internal cement bentonite slurry wall (Hotel 2 north of Card Sound *Discharge* Canal and one located at Turtle Point); and a cellular cofferdam located near the plant in the Barge Basin.

In September 2016, the CCS periphery including dams, dikes, berms, and appurtenant structures were inspected by an independent qualified safety professional in accordance with the Department's Consent Order (CO) (OGC No. 16-0241) that was issued in June 2016. For more information on the CO, see Part II Section 3 of this Fact Sheet. The cofferdam was inspected both above and below the waterline. No structural defects or breaches were identified in the resulting report, dated September 2016, submitted by FPL to the Department. The report did, however, include recommendations for maintaining and protecting the long-term integrity of the CCS. In early 2018, FPL completed a number of the recommendations, including: (1) repair of the tie rods, walers, steel corrosion, and crest road on the barge canal cofferdam; (2) backfill of the old C-107 canal (now S-20 Discharge Canal) cut on the CCS side of bank; (3) stabilization of slopes (both sides) for the Hotel 2 dam; and (4) removal of trees greater than 4 inches in diameter from perimeter berm slopes.

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In addition, the report included recommendations to inspect: (1) the CCS once every five years for the entire perimeter; and (2) the four small dams annually. Section VIII of the draft permit requires inspection of the CCS periphery, including the three dams, above and below the surface waterline for the entire perimeter by an independent qualified, State-registered professional engineer on a five-year basis and annually by a qualified, State-registered professional engineer. The term qualified means having successfully completed the Mine Safety and Health Administration Qualification for Impoundment Inspection course in addition to the Annual Retraining for Impoundment Qualification, or equivalent qualifications.

Furthermore, the draft permit requires FPL to submit to the Department an annual report of all impoundment inspections and maintenance activities, including corrective actions made in response to inspections, summarizing findings of all monitoring activities including the annual thermal efficiency evaluation of the CCS, remediation measures pertaining to the structural integrity, design, construction, and operation and maintenance of the CCS, and all other activities undertaken to repair or maintain the CCS.

The Department's CO requires the CCS to achieve a minimum 70 percent thermal efficiency and to control temperature and salinity. FPL has submitted a thermal efficiency plan to address water stage management, vegetation control, dredging, chemical additives to the CCS for facility operation, and upset recovery. FPL is implementing the efficiency plan and has been able to achieve greater than 70 percent thermal efficiency, and following permit issuance is required, under Section VIII of this draft permit, to monitor the thermal efficiency of the CCS in the months of April and August of each year.

Based on monitoring results, ~~FPL~~ *locations were* identified in the Turtle Point Canal and Barge Basin ~~locations~~ where water originating from the CCS ~~may~~ *could have* reach*ed* tidal surface waters connected to Biscayne Bay. The CO requires FPL to conduct restoration projects in the above canal and basin area to prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards in Biscayne Bay. ~~The restoration projects are on schedule to be completed in accordance with the schedule prescribed in the CO.~~ *The Turtle Point Canal restoration project is complete, and the Barge Basin restoration project is on schedule to be completed in accordance with the schedule prescribed in the CO.*

The CCS is unlined, and therefore, discharges to the Biscayne aquifer beneath the CCS. The Biscayne aquifer has an approximate depth of 100 feet below land surface on the westside of the CCS and an approximate depth of 130 feet on the east side out in the Bay. Groundwater beneath the CCS is Class G-III, non-potable water with a total dissolved solids (TDS) content of 10,000 milligrams per liter (mg/L) or greater.

Class G-III groundwater is also present west (inland) of the CCS, at depth within the Biscayne aquifer. Present above this inland Class G-III groundwater is Class G-II groundwater, potable water that has a TDS content of less than 10,000 mg/L. Class G-II groundwater lies to the west, northwest, north of the CCS. For purposes of this permit the contact or intersection of Class G-II and Class G-III groundwater is called a "saltwater interface".

Saline water from the CCS has moved, at depth, westward of the L-31E Canal in excess of those amounts that would have occurred without the existence of the CCS. Elevated salinity levels in the CCS cause, or at a minimum contribute to, the hypersaline discharges into the groundwater. The CO requires FPL to cease discharges from the CCS that impair the reasonable and beneficial use of the adjacent Class G-II groundwaters to the west of the CCS. FPL is currently conducting remedial activities to address hypersaline waters that have extended beyond the facility's western boundaries for which the compliance point is identified as the L-31E Canal per the CO.

3. RETIREMENT OF UNITS 1 AND 2

Former Units 1 and 2 began operation in 1967 and 1968, respectively. These units were converted from generation mode to synchronous condenser mode to provide voltage support to the transmission system in 2017 and 2011, respectively. The converted units do not generate wastewater. However, stormwater run-off from the units is covered under this permit.

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Process wastewater and stormwater associated with Units 1 and 2 were released to the CCS through an internal outfall designated as outfall I-002. Outfall I-002 piping from the basins to the CCS *has been removed*. ~~is scheduled for removal by January 1, 2019. Piping to the basins has already been capped.~~ Therefore, internal outfall I-002 has been removed from the draft permit.

4. DESCRIPTION OF WASTEWATER

Stormwater and wastewater associated with power generation and ancillary activities are released to the CCS. Point source discharges, as defined in Rule 62-620.200(37), F.A.C., from the facility to surface waters of the State are not authorized under this draft permit.

Stormwater runoff associated with loading and unloading operations, outdoor storage, outdoor process activities, and ancillary maintenance activities is directed toward the CCS. The quantities of stormwater generated from these activities are dependent on many variables, including the length and intensity of the storm event. Stormwater may come into contact with petroleum, oil, and lubricants used in industrial equipment which may leak onto impervious areas and become entrained in stormwater runoff. Stormwater may also come into contact with petroleum products, heavy metals, salts, anti-freeze and other automotive fluids which may be present at the onsite closed-loop vehicle wash area and vehicle access areas. Maintenance that consists of earth disturbance activities may also be a significant source of sediment. This draft permit requires development and implementation of a Best Management Practices Plan (see Section II.2.c.).

Wastewater generated by Units 3 and 4 (see flow diagram in Figure 4) includes intermittent chemical volume control system including wet lay-up, feedwater condensate including wet lay-up, on-line chemical analyzer, steam generator blowdown, condensate polisher backwash, reverse osmosis reject, circulating water pumps seal water, alternate flow from the circulating water pump seal water tank, non-equipment area stormwater, maintenance/wash through equipment area/closed cooling water system maintenance, plant intake screen wash, and non-contact once-through cooling water (OTCW), which is denoted as condenser and intake cooling water (ICW) on the figure.

Wastewater generated by Unit 5 (see flow diagram Figure 5) includes cooling water, emergency generator backup cooling water, non-equipment area stormwater, equipment area stormwater and plant drains following oil/water separation, and wastewater sump discharge which includes heat recovery steam generator blowdown, wastewater treatment system blowdown, and cooling water treatment reject.

I. PURPOSE

This is a renewal of the existing individual industrial wastewater discharge permit No. FL0001562 for the Turkey Point Power Plant. *This permit has been renewed in various forms since the early 1970s when the CCS became operational.* The objective of this permit is to ensure the cooling canal system (CCS) water does not impair designated uses of adjacent surface waters and groundwater as defined in Chapters 62-302, and 62-520, F.A.C. Elements of the draft permit are as follows.

1. DISCHARGES AND MONITORING

a. Internal Outfall and CCS

Wastewater enters the CCS at Internal Outfall I-001 (see Figure 3), which is the only permitted outfall authorized by this permit. This permit retains previous monitoring requirements for Internal Outfall I-001. This permit also includes additional monitoring at Internal Outfall I-001 and locations within the CCS, as well as locations beyond the CCS, necessary to characterize wastewater for evaluation of CCS wastewater beyond the facility boundaries. The 1972 Environmental Impact Statement acknowledges that some seepage of water from the CCS may reach surface waters. To the extent that such seepage occurs, it shall not cause or contribute to a violation of the surface water quality standards in Chapter 62-302, F.A.C. (see Tables II.1 and II.2 and Figure 6, Turkey Point Power Plant Groundwater, Surface Water, and Porewater Monitoring Locations, Figure 7, Turkey Point Power Plant Surface Water Monitoring

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Locations, Figure 8, Coastal Mangrove Porewater Monitoring Locations, and Figure 9, Turkey Point Power Plant Groundwater Monitoring Locations).

Table II.1 Monitoring Locations Within the Cooling Canal System

OUI - Sampling location for internal outfall designated as I-001.
TPSWCCS - Turkey Point Surface Water Cooling Canal System.

Sample Station ID	Location	Latitude			Longitude		
		o	'	"	o	'	"
OUI-1	Cooling water discharge prior to entering the feeder canal to the CCS	25	26	00.60	80	20	15.64
TPSWCCS-1	Northwest corner of the CCS	25	25	56.0	80	21	00.8
TPSWCCS-2	Central portion of the CCS	25	23	39.0	80	21	06.7
TPSWCCS-3	Southwestern portion of the CCS	25	21	52.4	80	22	02.4
TPSWCCS-4	Southern portion of the CCS near the Hotel 2 Dam	25	21	25.3	80	20	23.1
TPSWCCS-5	East-central portion of the CCS	25	23	18.4	80	19	54.4
TPSWCCS-6	Northeastern portion of the CCS	25	25	56.2	80	19	40.2
TPSWCCS-7	West-central portion of the CCS	25	24	07.6	80	21	39.4

Table II.2 Parameters monitored in the Cooling Canal System

Parameter	**Units**	**Rationale**
Temperature, Water	Deg F	62-4.070, and 62-620.320, F.A.C. (BPJ)
Solids, Total Suspended	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Biochemical Oxygen Demand (BOD)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Dissolved Oxygen (DO), % Saturation	percent	62-4.070, and 62-620.320, F.A.C. (BPJ)
Oxygen Reduction Potential	mv	62-4.070, and 62-620.320, F.A.C. (BPJ)
pH	s.u.	62-4.070, and 62-620.320, F.A.C. (BPJ)
Color	PCU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Solids, Total Dissolved	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Salinity	PSU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Specific Conductance	umhos/cm	62-4.070, and 62-620.320, F.A.C. (BPJ)
Turbidity	NTU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Ammonia, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Ammonia, Total Unionized (as NH_3)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Ammonium ion (NH_4^+)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrite plus Nitrate, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Kjeldahl, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Phosphate, Ortho (as PO_4)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Phosphorous, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Chlorophyll *a*	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Copper, Total Recoverable	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Iron, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Zinc, Total Recoverable	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Boron, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Chlorides (as Cl)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Magnesium, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)

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Parameter	Units	Rationale
Sodium, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Sulfate, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Sulfide, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Tritium	pCi/L	62-4.070, and 62-620.320, F.A.C. (BPJ)

b. Groundwater Monitoring (Groundwater Monitoring Group G-001)

Under this permit, CCS discharges to groundwater, both at and beyond the facility, will be monitored using a network of sixty-five monitoring wells (see Figure 9). The Biscayne aquifer will be monitored both laterally and vertically, with monitoring wells set in shallow, intermediate and deep zones. As shown in Figure 9, the network includes groundwater monitoring wells located in Biscayne Bay, the CCS, near the facility perimeter, and westward, or inland, of the facility.

During the period of operation authorized by this permit, FPL shall sample groundwater from the Biscayne aquifer from the following monitoring wells:

Table II.3 Groundwater Monitoring Well Locations

TPGW - Turkey Point Groundwater.
S - shallow, M - intermediate, and D - deep monitoring zones.
G-wells: Monitoring wells installed in 1972.
L-wells: Monitoring wells installed in 1974.

Monitoring Well ID	Description of Monitoring Location	Latitude			Longitude		
		o	'	"	o	'	"
TPGW-1S	West of Canal L-31E, west of northwest corner of the CCS (shallow)	25	26	4.7	80	21	15.8
TPGW-1M	West of Canal L-31E, west of northwest corner of the CCS (intermediate)	25	26	4.7	80	21	15.8
TPGW-1D	West of Canal L-31E, west of northwest corner of the CCS (deep)	25	26	4.7	80	21	15.8
TPGW-2S	West of the south-central portion of the CCS (shallow)	25	22	54.2	80	22	11.4
TPGW2M	West of the south-central portion of the CCS (intermediate)	25	22	54.2	80	22	11.4
TPGW-2D	West of the south-central portion of the CCS (deep)	25	22	54.2	80	22	11.4
TPGW-3S	South of the CCS (shallow)	25	20	42.1	80	20	51.9
TPGW-3M	South of the CCS (intermediate)	25	20	42.1	80	20	51.9
TPGW-3D	South of the CCS (deep)	25	20	42.1	80	20	51.9
TPGW-4S	Southwest Model Lands, at Tallahassee Road (shallow)	25	22	12.0	80	24	44.1
TPGW-4M	Southwest Model Lands, at Tallahassee Road (intermediate)	25	22	12.0	80	24	44.1
TPGW-4D	Southwest Model Lands, at Tallahassee Road (deep)	25	22	12.0	80	24	44.1
TPGW-5S	Northwest Model Lands – east of Tallahassee Road (shallow)	25	25	23.9	80	24	13.3
TPGW-5M	Northwest Model Lands – east of Tallahassee Road (intermediate)	25	25	23.9	80	24	13.3
TPGW-5D	Northwest Model Lands – east of Tallahassee Road (deep)	25	25	23.9	80	24	13.3
TPGW-6S	Northwest of the CCS, east of Homestead – Miami Speedway (shallow)	25	27	20.3	80	23	13.0
TPGW-6M	Northwest of the CCS, east of Homestead – Miami Speedway (intermediate)	25	27	20.3	80	23	13.0
TPGW-6D	Northwest of the CCS, east of Homestead – Miami Speedway (deep)	25	27	20.3	80	23	13.0
TPGW-7S	Northwest Model Lands (shallow)	25	26	02.5	80	25	40.7
TPGW-7M	Northwest Model Lands (intermediate)	25	26	02.5	80	25	40.7
TPGW-7D	Northwest Model Lands (deep)	25	26	02.5	80	25	40.7
TPGW-8S	West central Model Lands (shallow)	25	24	36.4	80	27	08.7
TPGW-8M	West central Model Lands (intermediate)	25	24	36.4	80	27	08.7
TPGW-8D	West central Model Lands (deep)	25	24	36.4	80	27	08.7

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Monitoring Well ID	Description of Monitoring Location	Latitude			Longitude		
		°	'	"	°	'	"
TPGW-9S	West of Card Sound Canal Road, southwest of CCS (shallow)	25	22	28.6	80	28	41.9
TPGW-9M	West of Card Sound Canal Road, southwest of CCS (intermediate)	25	22	28.6	80	28	41.9
TPGW-9D	West of Card Sound Canal Road, southwest of CCS (deep)	25	22	28.6	80	28	41.9
TPGW-10S	Biscayne Bay, channel entrance to Barge Basin (shallow)	25	26	27.4	80	19	29.0
TPGW-10M	Biscayne Bay, channel entrance to Barge Basin (intermediate)	25	26	27.4	80	19	29.0
TPGW-10D	Biscayne Bay, channel entrance to Barge Basin (deep)	25	26	27.4	80	19	29.0
TPGW-11S	Biscayne Bay, east of the CCS (shallow)	25	23	49.4	80	18	15.0
TPGW-11M	Biscayne Bay, east of the CCS (intermediate)	25	23	49.4	80	18	15.0
TPGW-11D	Biscayne Bay, east of the CCS (deep)	25	23	49.4	80	18	15.0
TPGW-12S	North of the CCS (shallow)	25	26	55.4	80	20	22.9
TPGW-12M	North of the CCS (intermediate)	25	26	55.4	80	20	22.9
TPGW-12D	North of the CCS (deep)	25	26	55.4	80	20	22.9
TPGW-13S	In the central portion of the CCS (shallow)	25	23	39.0	80	21	07.1
TPGW-13M	In the central portion of the CCS (intermediate)	25	23	39.0	80	21	07.1
TPGW-13D	In the central portion of the CCS (deep)	25	23	39.0	80	21	07.1
TPGW-14S	Biscayne Bay, southeast of the CCS (shallow)	25	21	15.5	80	19	34.5
TPGW-14M	Biscayne Bay, southeast of the CCS (intermediate)	25	21	15.5	80	19	34.5
TPGW-14D	Biscayne Bay, southeast of the CCS (deep)	25	21	15.5	80	19	34.5
TPGW-15S	Northwest corner of CCS (shallow)	25	25	56.9	80	21	2.5
TPGW-15M	Northwest corner of CCS (intermediate)	25	25	56.9	80	21	2.5
TPGW-15D	Northwest corner of CCS (deep)	25	25	56.9	80	21	2.5
TPGW-16S	East of the south-central portion of the CCS (shallow)	25	22	37.7	80	19	53.8
TPGW-16M	East of the south-central portion of the CCS (intermediate)	25	22	37.7	80	19	53.8
TPGW-16D	East of the south-central portion of the CCS (deep)	25	22	37.7	80	19	53.8
TPGW-17S	East of the L-31E canal, adjacent to S-20 structure (shallow)	25	22	71.4	80	22	53.2
TPGW-17M	East of the L-31E canal, adjacent to S-20 structure (intermediate)	25	22	1.4	80	22	32.2
TPGW-17D	East of the L-31E canal, adjacent to S-20 structure (deep)	25	22	1.4	80	22	32.2
TPGW-18S	Model Lands, west of L-3 (shallow)	25	25	12.5	80	22	17.8
TPGW-18M	Model Lands, west of L-3 (intermediate)	25	25	12.5	80	22	17.8
TPGW-18D	Model Lands, west of L-3 (deep)	25	25	12.5	80	22	17.8
TPGW-19S	Model Lands, north of Florida City Canal (shallow)	25	26	54.2	80	21	31.3
TPGW-19M	Model Lands, north of Florida City Canal (intermediate)	25	26	54.2	80	21	31.3
TPGW-19D	Model Lands, north of Florida City Canal (deep)	25	26	54.2	80	21	31.3
TPGW-20D	Adjacent to City of Homestead baseball complex	25	27	19.9	80	26	10.5
TPGW-21S	Converted USGS well G-3164 (shallow)	25	25	20.2	80	26	10
TPGW-21M	Converted USGS well G-3164 (intermediate)	25	25	20.2	80	26	10
TPGW-21D	Converted USGS well G-3164 (deep)	25	25	20.2	80	19	10
L-3	East of the L-31E canal, north-central portion of the CCS (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	25	09.7	80	21	28.7
L-5	East of the L-31E canal, south-central portion of the CCS (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	23	20.9	80	22	7.3
G-28	Tallahassee Rd, south of Model Lands basin (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	23	25.5	80	24	43.6
G-21	Tallahassee Rd, north of Model Lands basin (Not Automated). This well is an open-hole well, monitored at approximately 18 feet and 58 feet below land surface.	25	25	34.8	80	24	42.9

Under the FPL Turkey Point Power Plant Groundwater, Surface Water, and Ecological Monitoring Plan, which began in 2009, FPL conducted an assessment regarding the identification of potential tracer monitoring parameters for use in determining the occurrence of CCS waters in the region. FPL documented their findings in the August 2011

annual monitoring report submitted to SFWMD and the Department. Based on these findings, the Department identified tritium in conjunction with major seawater ions and other constituents to be monitored as a means of fingerprinting to be used by FPL in identifying CCS waters in the region. The wells in Table II.3 above shall be monitored for the following parameters.

Table II.4 Parameters monitored in Groundwater

Parameter	Units	Rationale
Temperature	Deg F	62-520, F.A.C.
Water Level Relative to NAVD	ft	62-520, F.A.C.
Specific Conductance	umhos/cm	62-520, F.A.C.
Salinity	PSU	62-520, F.A.C.
Fluid Density	g/cm^3	62-520, F.A.C.
pH	s.u.	62-520, F.A.C.
Solids, Total Dissolved (TDS)	mg/L	62-520, F.A.C.
Chloride (as Cl)	mg/L	62-520, F.A.C.
Sodium, Total	mg/L	62-520, F.A.C.
Calcium, Total	mg/L	62-520, F.A.C.
Potassium, Total	mg/L	62-520, F.A.C.
Iron, Total Recoverable	mg/L	62-520, F.A.C.
Tritium	pCi/L	Tracer (BPJ)
Nitrogen, Ammonia, Total (as N)	mg/L	62-520, F.A.C.
Ammonium ion (NH_4^+)	mg/L	62-520, F.A.C.
Ammonia, Total Unionized (as NH_3)	mg/L	62-520, F.A.C.
Nitrite plus Nitrate, Total (as N)	mg/L	62-520, F.A.C.
Nitrogen, Kjeldahl, Total (as N)	mg/L	62-520, F.A.C.
Nitrogen, Total	mg/L	62-520, F.A.C.
Phosphorus, Total (as P)	mg/L	62-520, F.A.C.
Phosphate, Ortho (as PO_4)	mg/L	62-520, F.A.C.
Boron, Total Recoverable	mg/L	62-520, F.A.C.
Magnesium, Total Recoverable	mg/L	62-520, F.A.C.
Sulfate, Total	mg/L	62-520, F.A.C.

The above listed parameters are report only except for Nitrite plus Nitrate, Total (as N), which has a limit of 10 mg/L in samples collected from monitoring wells TPGW-1, and TPGW-18.

Tritium will be collected quarterly and is being monitored as a tracer for identifying contributions of CCS water to the Biscayne aquifer.

In addition, permit condition II.D.8 prohibits the discharge of nuisance, acutely toxic, carcinogenic, mutagenic, teratogenic, and dangerous components in accordance with Rules 62-520.400, and 62-520.430, F.A.C.

c. Surface Water Monitoring (Biscayne Bay, L-31E Canal, S-20 Discharge Canal, Card Sound *Discharge* Canal) (Surface Water Monitoring Group D-01A)

Surface water monitoring as shown in Table II.5 is required in this permit to confirm that discharge from the CCS to groundwater does not impair the designated use of contiguous surface waters pursuant to Rule 62-520.310(2), F.A.C. Therefore, the same parameters are monitored in the CCS and surface waters of the State as discussed below.

Biscayne Bay is subject to the estuary-specific numeric nutrient criteria in Paragraph 62-302.532(1)(h), F.A.C. The Department updated the 303d lists of impaired waters in June 2017, identifying the majority of Biscayne Bay, including the South Central Biscayne Bay segments east of the facility as impaired for nutrients based on chlorophyll *a* levels. Section 403.067, F.S., implements section 303(d) of the Clean Water Act, and requires the Department to develop lists of impaired waters, and to develop Total Maximum Daily Loads (TMDL) for those waters. The Card

Sound segment of Biscayne Bay to the south of the facility is not identified as impaired for nutrients. ~~Biscayne Bay is not identified as impaired for any other parameters and has not been previously identified as impaired for nutrients.~~ Figure 10 provides a map of Biscayne Bay showing South Central and Card Sound bay segments.

In accordance with Paragraphs 62-302.700(9)(h)5, F.A.C., (Biscayne Bay, Cape Florida) and 62-302.700(9)(h)6, F.A.C., (Biscayne Bay, Card Sound) Biscayne Bay is an Outstanding Florida Water (OFW), and parts of the South Central and Card Sound bay segments are within the Biscayne Bay Aquatic Preserve. "Outstanding Florida Waters" means waters designated by the Environmental Regulation Commission as worthy of special protection because of their natural attributes as defined by Rule 62-302.200(26), F.A.C. Additionally, in accordance with Paragraph 62-302.700(9)(a)1, F.A.C., Biscayne National Park is an OFW and encompasses much of the Biscayne Bay estuary. Biscayne National Park is also an Outstanding National Resource Water in accordance with Paragraph 62-302.700(10)(a)1, F.A.C. "Outstanding National Resources Waters" means waters designated by the Environmental Regulation Commission that are of such exceptional recreational or ecological significance that water quality should be maintained and protected as defined by Rule 62-302.200(27), F.A.C.

The L-31E canal is approximately parallel to the western boundary of the CCS, and the S-20 Discharge Canal is parallel to the southwest and south sides of the CCS. These canals are controlled by the SFWMD. Salinity in the canals fluctuates seasonally.

The L-31E canal was primarily constructed as a barrier to prevent salinity intrusion to locations west of the canal. The L-31E canal collects water from other drainage canals in the area. The L-31E canal discharges into Biscayne Bay through the S-20 Discharge Canal.

Table II.5 Surface Water Monitoring Locations

TPBBSW - Turkey Point Biscayne Bay Surface Water.
TPSWC - Adjacent Surface Water Canals.
T - Top samples, B - Bottom samples.

Sample Station ID	Location	Latitude			Longitude		
		o	'	"	o	'	"
TPBBSW-3	Biscayne Bay	25	23	49.38	80	18	14.82
TPBBSW-4	Biscayne Bay	25	20	40.34	80	19	43.90
TPBBSW-5	Biscayne Bay	25	19	13.69	80	22	1.70
TPBBSW-7T	Biscayne Bay near Turtle Point Canal Dam	25	25	9.99	80	19	42.15
~~TPBBSW-8~~	~~Terminus of Barge Canal~~	~~25~~	~~25~~	~~12.61~~	~~80~~	~~19~~	~~29.89~~
TPBBSW-10	Biscayne Bay	25	26	27.83	80	19	22.92
TPBBSW-14	Biscayne Bay	25	25	15.50	80	19	34.50
TPSWC-1B TPSWC-1T	L-31E Canal	25	25	58.44	80	21	11.87
TPSWC-2B TPSWC-2T	L-31E Canal	25	24	21.20	80	21	46.30
TPSWC-3B TPSWC-3T	L-31E Canal	25	22	10.47	80	22	33.00
TPSWC-4B TPSWC-4T	S-20 Canal	25	21	24.10	80	22	3.00
TPSWC-5B TPSWC-5T	Card Sound *Discharge* Canal at Hotel 2 Dam	25	21	24.62	80	20	18.70

Table II.6 Parameters monitored in Surface Waters

Parameter	Units	Rationale
Temperature, Water	Deg F	62-4.070, and 62-620.320, F.A.C. (BPJ)
pH	s.u.	62-4.070, and 62-620.320, F.A.C. (BPJ)
Solids, Total Dissolved (TDS)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Salinity	PSU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Specific Conductance	umhos/ cm	62-4.070, and 62-620.320, F.A.C. (BPJ)
Turbidity	NTU	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Ammonia, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Ammonia, Total Unionized (as NH_3)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Ammonium ion (NH_4^+)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrite plus Nitrate, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Kjeldahl, Total (as N)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Nitrogen, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Phosphate, Ortho (as PO_4)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Phosphorous, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Chlorophyll *a*	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Copper, Total Recoverable	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Iron, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Zinc, Total Recoverable	ug/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Boron, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Chlorides (as Cl)	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Magnesium, Total Recoverable	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Sodium, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Sulfate, Total	mg/L	62-4.070, and 62-620.320, F.A.C. (BPJ)
Tritium	pCi/L	62-4.070, and 62-620.320, F.A.C. (BPJ)

d. Porewater Monitoring

Table II.7 Porewater Monitoring Locations (Surface Water Monitoring Group D-02A)

During the period of operation authorized by this permit, the permittee shall sample porewater (free water present in sediments) from coastal marine wetlands north, east, and south of the CCS from locations described below in accordance with the protocols set forth in FPL's Quality Assurance Project Plan dated 2013:

Porewater Monitoring ID	Description of Monitoring Location	Latitude			Longitude		
PW M1-2	Coastal marine wetlands; ½ mile north of power block	25	26	49.8	80	19	57.7
PW M2-2	Coastal marine wetlands; east of CCS, 2 miles south of power block	25	24	18.8	80	19	47.6
PW M3-2	Coastal marine wetlands; east of CCS, 3.4 miles south of power block	25	23	4.2	80	19	40.6

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PW M4-2	Coastal marine wetlands; southeast corner of CCS	25	21	16.8	80	19	44.9
PW M5-2	Coastal marine wetlands; south of CCS	25	20	56	80	20	33
PW M6-1	Coastal marine wetlands; west of Card Sound Road (background location)	25	17	40.1	80	23	46.8

Table II.8 Parameters monitored in Porewater

Parameter	Units	Sample Type	Monitoring Frequency
Temperature	Deg F	Grab	Semi-Annually
pH	s.u.	Grab	Semi-Annually
Specific Conductance	µmhos/cm	Grab	Semi-Annually
Salinity	PSU	Grab	Semi-Annually
Fluid Density	g/cm^3	Grab	Semi-Annually
Solids, Total Dissolved (TDS)	mg/L	Grab	Semi-Annually
Chloride (as Cl)	mg/L	Grab	Semi-Annually
Sodium, Total	mg/L	Grab	Semi-Annually
Calcium, Total	mg/L	Grab	Semi-Annually
Potassium, Total	mg/L	Grab	Semi-Annually
Boron, Total Recoverable	mg/L	Grab	Semi-Annually
Copper, Total Recoverable	ug/L	Grab	Semi-Annually

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Iron, Total Recoverable	mg/L	Grab	Semi-Annually
Zinc, Total Recoverable	ug/L	Grab	Semi-Annually
Magnesium, Total Recoverable	mg/L	Grab	Semi-Annually
Sulfate, Total	mg/L	Grab	Semi-Annually
Tritium	pCi/L	Grab	Semi-Annually
Nitrogen, Ammonia, Total (as N)	mg/L	Grab	Semi-Annually
Ammonium ion (as NH_4)	mg/L	Grab	Semi-Annually
Ammonia, Total Unionized (as NH_3)	mg/L	Grab	Semi-Annually
Nitrite plus Nitrate, Total (as N)	mg/L	Grab	Semi-Annually
Nitrogen, Kjeldahl, Total (as N)	mg/L	Grab	Semi-Annually
Nitrogen, Total (as N)	mg/L	Grab	Semi-Annually
Phosphorus, Total (as P)	mg/L	Grab	Semi-Annually
Phosphate, Ortho (as PO_4)	mg/L	Grab	Semi-Annually

2. NEW PERMIT CONDITIONS

a. Nutrient Monitoring and Annual Reporting

The draft permit requires FPL to submit an annual nutrient monitoring summary report based on at least 24 months of groundwater, surface water, and CCS monitoring data to the Department. The report is to be submitted by ~~November~~ *August 31st* of each year, commencing in the third year following permit issuance. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.), Florida Statute, applicable portions of the report must be signed and sealed by the professional(s) who prepared them. The report is required to include by station and depth where specified:

a. Annual geometric mean (AGM) concentrations by nutrient parameter;
b. Arithmetic mean;
c. Percentiles including 25th, 75th, and 90th, number of samples collected by parameter; and

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d. Evaluation of trends over the period of record by parameter.

b. Impoundment Conditions

FPL is required to properly operate and maintain all treatment and control facilities used to achieve compliance with this permit. Impoundments, including the CCS, used to treat or store wastewater are considered to be treatment and control facilities and are subject to the operation and maintenance requirements in this permit.

The permit includes new requirements to address impoundment construction, operation, and maintenance, including periodic inspections by trained personnel who are knowledgeable in impoundment design and safety. In addition, annual inspections by qualified responsible officials are required. Increased monitoring is required after large precipitation events, when there is an increased stress to impoundments and a greater potential for impacts on integrity. In response to any changes, such as cracks, erosion, bulges, and changes in seepage that may compromise their integrity, FPL is also required to respond in a timely manner. The permit requires documenting the results of the annual inspections and reporting the remedial activities taken, as well as timely reporting of changes to integrity and associated corrective actions.

The permittee shall take actions that will allow the thermal efficiency of the CCS to achieve a minimum annual average of 70 percent. The CCS shall be monitored at an annual average of its thermal efficiency determined, as is prescribed in the Turkey Point Thermal Efficiency Plan. The findings of each inspection including thermal efficiency shall be documented in a written annual inspection report as described in permit condition VIII.G.1.

c. Best Management Practices Plan

FPL is required to develop and implement a Best Management Practices Plan (Plan) to prevent or minimize the generation and the potential for the release of pollutants (including mercury per Rule 62-304.900, F.A.C., copper, iron, zinc, and nutrients) from facility operations (including spillage, leaks, and material and waste handling and storage activities) to industrial wastewater and stormwater in the CCS. FPL must develop and implement provisions of the Plan in accordance with Section VII of the permit.

e. Monitoring

The draft permit requires FPL to monitor groundwater, surface water, and porewater (see Figure 6). Groundwater monitoring consists of an existing network of sixty-five monitoring wells (see Figure 9). The Biscayne aquifer will be monitored both laterally and vertically, with monitoring wells set in shallow, intermediate and deep zones. As shown in Figure 9, the network includes groundwater monitoring wells located in Biscayne Bay, the CCS, near the facility perimeter, and westward, or inland, of the facility.

The surface watering monitoring consists of 20 monitoring sites – six in canals adjacent to the CCS, seven within the CCS, and seven in Biscayne Bay (see Figure 7). The previous permit included one of the monitoring sites in the CCS. The other nineteen monitoring sites are existing from other monitoring programs, and were selected to be included in this draft permit. Parameters include temperature, total suspended solids, pH, salinity, specific conductance, copper, iron and zinc.

Porewater monitoring consists of six sites located in coastal mangroves (see Figure 8). One site is located to establish background conditions. The other five are located to establish water quality conditions north, east and south of the CCS. The six porewater sites are existing from other monitoring programs, and were selected to be included in this draft permit. Parameters monitored at the porewater and surface water sites are the same. The draft permit requires FPL to take action to lower copper, iron, zinc and nitrate and nitrite in the CCS water if the levels reach certain thresholds.

3. CONSENT ORDER (OGC File No. 16-0241)

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On June 20, 2016, FPL entered into a Consent Order (CO) with the Department to resolve a Notice of Violation (NOV) dated April 25, 2016. The CO ~~finds~~ *found* that elevated salinity levels in the CCS cause, or at a minimum contribute to, hypersaline discharges into the groundwater. *The CO also found that* ~~T~~*t*he CCS ~~is~~ *was* the major continuing cause of the westward movement of the saltwater interface (the intersection of Class G-II and G-III groundwaters), and that the discharge of hypersaline water contributes to saltwater intrusion. (The phrase "hypersaline" as used in the CO means water that exceeds 19,000 mg/L of chlorides). *The CO found that* ~~S~~*s*altwater intrusion into the area west of the CCS ~~is~~ *was* impairing the reasonable and beneficial use of adjacent G-II groundwater in that area. The CO stipulates remedial actions and timelines for achieving compliance with the following objectives:

a. cease discharges from the CCS that impair the reasonable and beneficial use of the adjacent Class G-II ground waters to the west of the CCS in violation of Condition I.1 (formerly Condition IV.1) of the Permit and Rule 62-520.400, F.A.C.;

b. prevent releases of groundwater from the CCS to surface waters connected to Biscayne Bay that result in exceedances of surface water quality standards; and

c. provide mitigation for impacts related to the historic operation of the CCS, including but not limited to the hypersaline plume and its influence on the saltwater interface.

After FPL has demonstrated to the Department that it has fulfilled the requirements of the CO, all requirements of the CO will be terminated except for the requirement to maintain the average annual salinity of the CCS at or below 34 practical salinity until an average annual salinity of the CCS is designated in a Department permit.

4. THE ADMINISTRATIVE RECORD

The administrative record including application, draft permit, fact sheet, public notice (after release), comments received and additional information is available for public inspection during normal business hours at the location specified in Section 8. Copies will be provided at a minimal charge per page.

5. PROPOSED SCHEDULE FOR PERMIT ISSUANCE

Draft Permit and Public Notice to Applicant and U.S. Environmental Protection Agency (EPA)	January 2, 2019
Public Comment Period	Beginning: February 1, 2019 Ending: March 3, 2019
Notice of Intent to Issue	April 2, 2019
Notice of Permit Issuance	April 23, 2019

6. DEPARTMENTOF ENVIRONMENTAL PROTECTION CONTACT

Additional information concerning the permit and proposed schedule for permit issuance may be obtained during normal business hours from:

Marc Harris, P.E.
Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road, Mail Station 3545
Tallahassee, Florida 32399-2400
Telephone Number: (850) 245-8589

Fax Number: (850) 245-8669

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7. PROCEDURES FOR THE FORMULATION OF FINAL DETERMINATIONS

a. Public Comment Period

The Department of Environmental Protection proposes to issue a wastewater facility permit to this applicant subject to the aforementioned effluent limitations and conditions. This decision is tentative and open to comment from the public.

Interested persons are invited to submit written comments regarding permit issuance on the draft permit limitations and conditions to the following address:

Department of Environmental Protection
2600 Blair Stone Road
Mail Station 3545
Tallahassee, Florida 32399-2400
Attn.: Marc Harris, P.E.

All comments received within 30 days following the date of public notice, pursuant to Rule 62-620.550, F.A.C., will be considered in the formulation of the final decision with regard to permit issuance.

Any interested person may submit written comments on the Department's proposed permitting decision or may submit a written request for a public meeting to the address specified above, in accordance with Rule 62-620.555, F.A.C. The comments or request for a public meeting must contain the information set forth below and must be received in the above address of the Department within 30 days of receipt or publication of the public notice. Failure to submit comments or request a public meeting within this time period will constitute a waiver of any right such person may have to submit comments or request a public meeting under Rule 62-620.555, F.A.C.

The comments or request for a public meeting shall contain the following information:
(1) The commenter's name, address and telephone number, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(2) A statement of how and when notice of the draft permit was received;
(3) A description of any changes the commenter proposes for the draft permit;
(4) A full explanation of the factual and legal reasons for each proposed change to the draft permit; and
(5) A request that a public meeting be scheduled (if applicable) including a statement of the nature of the issues proposed to be raised at the meeting.

b. Public Meeting

The Department will hold a public meeting if there is a significant degree of public interest in the draft permit or if it determines that useful information and data may be obtained thereby. Public notice of such a meeting shall be published by the applicant at least 30 days prior to the meeting.

If a public meeting is scheduled the public comment period is extended until the close of the public meeting. If a public meeting is held any person may submit oral or written statements and data at the meeting on the Department's proposed action.

c. Issuance of the Permit

The Department will make its decision regarding permit issuance after consideration of all written comments, including comments from the EPA on surface water discharge (NPDES) aspects of the draft or proposed permit; the requirements of Chapter 403, F.S., and appropriate rules; and, if a public meeting is held, after consideration of all comments, statements and data presented at the public meeting. The Department will respond to all significant comments in writing. The Department's response to significant comments will be included in the administrative record of the permit and will be available for public inspection at the above address of the Department.

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Unless a request for an administrative hearing, or an extension of time to file a petition for an administrative hearing, pursuant to Chapter 120, F.S., as indicated in d. below, is granted, the Department will take final agency action by issuing the permit or denying the permit application. If an administrative hearing is convened, final agency action will be based on the outcome of the hearing.

d. Administrative Hearing

A person whose substantial interests are affected by the Department's proposed permitting decision has the opportunity to petition for an administrative proceeding (hearing) to challenge the Department's decision in accordance with Section 120.57, F.S.

An administrative hearing is an evidentiary proceeding in which evidence is presented by testimony and exhibits before an independent hearing officer. The result of an administrative hearing is the issuance of the hearing officer's recommended order to the Department, including the hearing officer's findings of fact, based on the evidence presented at the hearing. The Department will issue a final order, granting or denying the permit, based on the hearing officer's recommended order.

The petition for an administrative hearing must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000, within 14 days of publication of notice of agency action or within 14 days of personal receipt of notice of agency action, whichever occurs first. The petitioner is to mail a copy of the petition to the applicant at the time of filing. Failure to file a petition within this time period will constitute a waiver of any right such person may have to request an administrative determination (hearing) under section 120.57, F.S. The petition is to contain the following information:

(1) The name, address and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(2) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(3) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(4) A statement of the material facts which the petitioner contends warrant reversal or modification of the Department's action or proposed action;
(5) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and
(6) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in the notice of agency action. Persons whose substantial interests will be affected by any decision of the Department on the application have the right to petition to become a party to the proceeding, regardless of their agreement or disagreement with the Department's proposed action indicated in the notice of agency action.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St

Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-01A
MONITORING GROUP DESCRIPTION: A new permitted series of surface water monitoring sites in Biscayne Bay, L-31E canal, S-20 canal and Card Sound canal that monitors surface waters.

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 6 Mon. Site No. SWD-2	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 P Mon. Site No. SWD-2	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 Q Mon. Site No. SWD-3	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 R Mon. Site No. SWD-3	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 S Mon. Site No. SWD-4	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 T Mon. Site No. SWD-4	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

DRAFT

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 U Mon. Site No. SWD-5	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 V Mon. Site No. SWD-5	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 W Mon. Site No. SWD-6	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 1 Mon. Site No. SWD-6	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 5 Mon. Site No. SWD-7	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 A Mon. Site No. SWD-7	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 B Mon. Site No. SWD-8	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 G Mon. Site No. SWD-8	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 7 Mon. Site No. SWD-9	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 I Mon. Site No. SWD-9	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 J Mon. Site No. SWD-10	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 K Mon. Site No. SWD-10	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 Y Mon. Site No. SWD-11	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 0 Mon. Site No. SWD-11	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Top)	Sample Measurement										
PARM Code 00011 2 Mon. Site No. SWD-12	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Temperature (F), Water (Bottom)	Sample Measurement										
PARM Code 00011 3 Mon. Site No. SWD-12	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Salinity (Top)	Sample Measurement										
PARM Code 00480 6 Mon. Site No. SWD-8	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 P Mon. Site No. SWD-8	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Top)	Sample Measurement										
PARM Code 00480 Q Mon. Site No. SWD-9	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 R Mon. Site No. SWD-9	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Salinity (Top)	Sample Measurement										
PARM Code 00480 S Mon. Site No. SWD-10	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 T Mon. Site No. SWD-10	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Top)	Sample Measurement										
PARM Code 00480 U Mon. Site No. SWD-11	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 V Mon. Site No. SWD-11	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Top)	Sample Measurement										
PARM Code 00480 W Mon. Site No. SWD-12	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity (Bottom)	Sample Measurement										
PARM Code 00480 1 Mon. Site No. SWD-12	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ppt		Monthly	In Situ
Salinity	Sample Measurement										
PARM Code 00480 5 Mon. Site No. SWD-1	Permit Requirement						Report (Mo.Avg.)	ppt		Monthly	Calculated
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 6 Mon. Site No. SWD-1	Permit Requirement						Report (Mo.Avg.)	mg/L		Monthly	Calculated

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St
Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-01A
MONITORING GROUP DESCRIPTION: A new permitted series of surface water monitoring sites in Biscayne Bay, L-31E canal, S-20 canal and Card Sound canal that monitors surface waters.

REPORT FREQUENCY: Quarterly
PROGRAM: Industrial

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH (Top)	Sample Measurement										
PARM Code 00400 6 Mon. Site No. SWD-2	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 P Mon. Site No. SWD-2	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 Q Mon. Site No. SWD-3	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 R Mon. Site No. SWD-3	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 S Mon. Site No. SWD-4	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 T Mon. Site No. SWD-4	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH (Top)	Sample Measurement										
PARM Code 00400 U Mon. Site No. SWD-5	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 V Mon. Site No. SWD-5	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 W Mon. Site No. SWD-6	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 1 Mon. Site No. SWD-6	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 5 Mon. Site No. SWD-7	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 A Mon. Site No. SWD-7	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 B Mon. Site No. SWD-8	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 G Mon. Site No. SWD-8	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 7 Mon. Site No. SWD-9	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 I Mon. Site No. SWD-9	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH (Top)	Sample Measurement										
PARM Code 00400 J Mon. Site No. SWD-10	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 K Mon. Site No. SWD-10	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 Y Mon. Site No. SWD-11	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 0 Mon. Site No. SWD-11	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Top)	Sample Measurement										
PARM Code 00400 2 Mon. Site No. SWD-12	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
pH (Bottom)	Sample Measurement										
PARM Code 00400 3 Mon. Site No. SWD-12	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	In Situ
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Top)	Sample Measurement										
PARM Code 70295 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Solids, Total Dissolved (TDS) (Bottom)	Sample Measurement										
PARM Code 70295 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Top)	Sample Measurement										
PARM Code 00095 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ
Specific Conductance (Bottom)	Sample Measurement										
PARM Code 00095 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	In Situ

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Turbidity (Top)	Sample Measurement										
PARM Code 00070 6 Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 P Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Top)	Sample Measurement										
PARM Code 00070 Q Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 R Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Top)	Sample Measurement										
PARM Code 00070 S Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 T Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Top)	Sample Measurement										
PARM Code 00070 U Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 V Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Top)	Sample Measurement										
PARM Code 00070 W Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Turbidity (Bottom)	Sample Measurement										
PARM Code 00070 1 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab

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ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as N) (Top)	Sample Measurement										
PARM Code 00610 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00610 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Top)	Sample Measurement										
PARM Code 00619 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Ammonia, Unionized (as NH3) (Bottom)	Sample Measurement										
PARM Code 00619 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Top)	Sample Measurement										
PARM Code 71845 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrogen, Ammonia, Total (as NH4) (Bottom)	Sample Measurement										
PARM Code 71845 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Calculated
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Top)	Sample Measurement										
PARM Code 00630 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N) (Bottom)	Sample Measurement										
PARM Code 00630 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Top)	Sample Measurement										
PARM Code 00625 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N) (Bottom)	Sample Measurement										
PARM Code 00625 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 6 Mon. Site No. SWD-2	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 P Mon. Site No. SWD-2	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 Q Mon. Site No. SWD-3	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 R Mon. Site No. SWD-3	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 S Mon. Site No. SWD-4	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 T Mon. Site No. SWD-4	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 U Mon. Site No. SWD-5	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 V Mon. Site No. SWD-5	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 W Mon. Site No. SWD-6	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 1 Mon. Site No. SWD-6	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 5 Mon. Site No. SWD-7	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 A Mon. Site No. SWD-7	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 B Mon. Site No. SWD-8	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 G Mon. Site No. SWD-8	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 7 Mon. Site No. SWD-9	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 I Mon. Site No. SWD-9	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 J Mon. Site No. SWD-10	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 K Mon. Site No. SWD-10	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 Y Mon. Site No. SWD-11	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 0 Mon. Site No. SWD-11	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total (Top)	Sample Measurement										
PARM Code 00600 2 Mon. Site No. SWD-12	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Total (Bottom)	Sample Measurement										
PARM Code 00600 3 Mon. Site No. SWD-12	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant MONITORING GROUP NUMBER: D-01A PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Top)	Sample Measurement										
PARM Code 00660 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4) (Bottom)	Sample Measurement										
PARM Code 00660 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 6 Mon. Site No. SWD-2	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 P Mon. Site No. SWD-2	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 Q Mon. Site No. SWD-3	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 R Mon. Site No. SWD-3	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 S Mon. Site No. SWD-4	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 T Mon. Site No. SWD-4	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 U Mon. Site No. SWD-5	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 V Mon. Site No. SWD-5	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 W Mon. Site No. SWD-6	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 1 Mon. Site No. SWD-6	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 5 Mon. Site No. SWD-7	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 A Mon. Site No. SWD-7	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 B Mon. Site No. SWD-8	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 G Mon. Site No. SWD-8	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 7 Mon. Site No. SWD-9	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 I Mon. Site No. SWD-9	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 J Mon. Site No. SWD-10	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 K Mon. Site No. SWD-10	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 Y Mon. Site No. SWD-11	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 0 Mon. Site No. SWD-11	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Top)	Sample Measurement										
PARM Code 00665 2 Mon. Site No. SWD-12	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P) (Bottom)	Sample Measurement										
PARM Code 00665 3 Mon. Site No. SWD-12	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Top)	Sample Measurement										
PARM Code 32230 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Chlorophyll a (Bottom)	Sample Measurement										
PARM Code 32230 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Top)	Sample Measurement										
PARM Code 01119 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Copper, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01119 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Iron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00980 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Iron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00980 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Top)	Sample Measurement										
PARM Code 01094 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 01094 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	ug/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Top)	Sample Measurement										
PARM Code 00999 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Boron, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00999 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Top)	Sample Measurement										
PARM Code 00940 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl) (Bottom)	Sample Measurement										
PARM Code 00940 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00921 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Magnesium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00921 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sodium, Total Recoverable (Top)	Sample Measurement										
PARM Code 00923 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable (Bottom)	Sample Measurement										
PARM Code 00923 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 6 Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 P Mon. Site No. SWD-2	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 Q Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 R Mon. Site No. SWD-3	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 S Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 T Mon. Site No. SWD-4	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 U Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 V Mon. Site No. SWD-5	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 W Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 1 Mon. Site No. SWD-6	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 5 Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 A Mon. Site No. SWD-7	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 B Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 G Mon. Site No. SWD-8	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 7 Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 I Mon. Site No. SWD-9	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 J Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 K Mon. Site No. SWD-10	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-01A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 Y Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 0 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Top)	Sample Measurement										
PARM Code 00945 2 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfate, Total (Bottom)	Sample Measurement										
PARM Code 00945 3 Mon. Site No. SWD-12	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Turbidity	Sample Measurement										
PARM Code 00070 5 Mon. Site No. SWD-11	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab

DRAFT

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St
Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-02A
MONITORING GROUP DESCRIPTION: A new permitted series of porewater (free water present in sediments) monitoring sites in coastal marine wetlands north, east, and south of the facility s onsite CCS.

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT FREQUENCY: Semi-annually
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water	Sample Measurement										
PARM Code 00011 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab
Temperature (F), Water	Sample Measurement										
PARM Code 00011 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	Deg F		Semi-Annually; twice per year	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

DRAFT

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
pH	Sample Measurement										
PARM Code 00400 P Mon. Site No. OTH-1	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 Q Mon. Site No. OTH-2	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 R Mon. Site No. OTH-3	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 S Mon. Site No. OTH-4	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 T Mon. Site No. OTH-5	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
pH	Sample Measurement										
PARM Code 00400 U Mon. Site No. OTH-6	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant MONITORING GROUP NUMBER: D-02A PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Specific Conductance	Sample Measurement										
PARM Code 00095 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	umhos/cm		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Salinity	Sample Measurement										
PARM Code 00480 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	ppt		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Fluid Density	Sample Measurement										
PARM Code 71820 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Fluid Density	Sample Measurement										
PARM Code 71820 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	g/ml		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant MONITORING GROUP NUMBER: D-02A PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant MONITORING GROUP NUMBER: D-02A PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant MONITORING GROUP NUMBER: D-02A PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Calcium, Total Recoverable	Sample Measurement										
PARM Code 00918 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Potassium, Total	Sample Measurement										
PARM Code 00937 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant MONITORING GROUP NUMBER: D-02A PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Sulfate, Total	Sample Measurement										
PARM Code 00945 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 P Mon. Site No. OTH-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 Q Mon. Site No. OTH-2	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 R Mon. Site No. OTH-3	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 S Mon. Site No. OTH-4	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: D-02A

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 T Mon. Site No. OTH-5	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Phosphate, Ortho (as P)	Sample Measurement										
PARM Code 70507 U Mon. Site No. OTH-6	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St
Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESCRIPTION: Once-through non-contact cooling water and other wastewater to the closed cooling canal system.

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water	Sample Measurement										
PARM Code 00011 P Mon. Site No. OUI-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	Deg F		Monthly	In Situ
Biochemical Oxygen Demand-5	Sample Measurement										
PARM Code 00310 P Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Monthly	Grab
Oxygen, Dissolved Percent Saturation	Sample Measurement										
PARM Code 00301 P Mon. Site No. CAL-1	Permit Requirement				Report (Min.Mo.Avg.)			percent		Monthly	Calculated
Oxidation-Reduction Potential	Sample Measurement										
PARM Code 00090 P Mon. Site No. CAL-1	Permit Requirement		Report (Day.Max.)	mV						Monthly	Meter
Color	Sample Measurement										
PARM Code 00080 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	PCU		Monthly	Grab
Salinity	Sample Measurement										
PARM Code 00480 P Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	ppt		Monthly	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: I-001

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Salinity	Sample Measurement										
PARM Code 00480 R Mon. Site No. CAL-1	Permit Requirement						Report (Mo.Avg.)	ppt		Monthly	Grab
Salinity	Sample Measurement										
PARM Code 00480 Y Mon. Site No. CAL-1	Permit Requirement					Report (An.Avg.)		ppt		Daily; 24 hours	Grab

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St
Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESCRIPTION: Once-through non-contact cooling water and other wastewater to the closed cooling canal system.

REPORT FREQUENCY: Quarterly
PROGRAM: Industrial

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
pH	Sample Measurement										
PARM Code 00400 P Mon. Site No. OUI-1	Permit Requirement				Report (Day.Min.)		Report (Day.Max.)	s.u.		Quarterly	Grab
Solids, Total Dissolved (TDS)	Sample Measurement										
PARM Code 70295 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Specific Conductance	Sample Measurement										
PARM Code 00095 P Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	umhos/cm		Quarterly	Grab
Turbidity	Sample Measurement										
PARM Code 00070 P Mon. Site No. CAL-2	Permit Requirement						Report (Day.Max.)	NTU		Quarterly	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DRAFT

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: I-001

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as NH4)	Sample Measurement										
PARM Code 71845 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 P Mon. Site No. OUI-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: I-001

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total	Sample Measurement										
PARM Code 00600 Q Mon. Site No. CAL-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Phosphate, Ortho (as PO4)	Sample Measurement										
PARM Code 00660 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4)	Sample Measurement										
PARM Code 00660 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 P Mon. Site No. OUI-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 Q Mon. Site No. CAL-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Chlorophyll a	Sample Measurement										
PARM Code 32230 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chlorophyll a	Sample Measurement										
PARM Code 32230 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sodium, Total Recoverable	Sample Measurement										
PARM Code 00923 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab
Sulfide, Total	Sample Measurement										
PARM Code 00745 P Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Quarterly	Grab

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed submit this report to: http://www.fldepportal.com/go/

PERMITTEE NAME: FPL
MAILING ADDRESS: 700 Universe Blvd
Juno Beach, Florida 33408-

FACILITY: FPL Turkey Point Plant
LOCATION: 9700 SW 344th St
Homestead, FL 33035-1800

COUNTY: Miami-Dade
OFFICE: Tallahassee

PERMIT NUMBER: FL0001562-012-IW1N

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-001
MONITORING GROUP DESCRIPTION: Once-through non-contact cooling water and other wastewater to the closed cooling canal system.

REPORT FREQUENCY: Semi-annually
PROGRAM: Industrial

RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	ug/L		Semi-Annually; twice per year	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 Q Mon. Site No. CAL-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

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ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: FPL Turkey Point Plant

MONITORING GROUP NUMBER: I-001

PERMIT NUMBER: FL0001562-012-IW1N

MONITORING PERIOD From: _____ To: _____

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Boron, Total Recoverable	Sample Measurement										
PARM Code 00999 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Magnesium, Total Recoverable	Sample Measurement										
PARM Code 00921 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Sulfate, Total	Sample Measurement										
PARM Code 00945 P Mon. Site No. OUI-1	Permit Requirement						Report (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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ISSUANCE/REISSUANCE DATE:
DMR EFFECTIVE DATE: 1st day of the 2nd month following effective date of permit - Permit expiration

INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT

Read these instructions before completing the DMR. Hard copies and/or electronic copies of the required parts of the DMR were provided with the permit. All required information shall be completed in full and typed or printed in ink. A signed, original DMR shall be mailed to the address printed on the DMR by the 28th of the month following the monitoring period. Facilities who submit their DMR(s) electronically through eDMR do not need to submit a hardcopy DMR. The DMR shall not be submitted before the end of the monitoring period.

The DMR consists of three parts--A, B, and D--all of which may or may not be applicable to every facility. Facilities may have one or more Part A's for reporting effluent or reclaimed water data. All domestic wastewater facilities will have a Part B for reporting daily sample results. Part D is used for reporting ground water monitoring well data.

When results are not available, the following codes should be used on parts A and D of the DMR and an explanation provided where appropriate. Note: Codes used on Part B for raw data are different.

CODE	DESCRIPTION/INSTRUCTIONS
ANC	Analysis not conducted.
DRY	Dry Well
FLD	Flood disaster.
IFS	Insufficient flow for sampling.
LS	Lost sample.
MNR	Monitoring not required this period.

CODE	DESCRIPTION/INSTRUCTIONS
NOD	No discharge from/to site.
OPS	Operations were shutdown so no sample could be taken.
OTH	Other. Please enter an explanation of why monitoring data were not available.
SEF	Sampling equipment failure.

When reporting analytical results that fall below a laboratory's reported method detection limits or practical quantification limits, the following instructions should be used, unless indicated otherwise in the permit or on the DMR:

1. Results greater than or equal to the PQL shall be reported as the measured quantity.
2. Results less than the PQL and greater than or equal to the MDL shall be reported as the laboratory's MDL value. These values shall be deemed equal to the MDL when necessary to calculate an average for that parameter and when determining compliance with permit limits.
3. Results less than the MDL shall be reported by entering a less than sign ("<") followed by the laboratory's MDL value, e.g. < 0.001. A value of one-half the MDL or one-half the effluent limit, whichever is lower, shall be used for that sample when necessary to calculate an average for that parameter. Values less than the MDL are considered to demonstrate compliance with an effluent limitation.

PART A -DISCHARGE MONITORING REPORT (DMR)

Part A of the DMR is comprised of one or more sections, each having its own header information. Facility information is preprinted in the header as well as the monitoring group number, whether the limits and monitoring requirements are interim or final, and the required submittal frequency (e.g. monthly, annually, quarterly, etc.). Submit Part A based on the required reporting frequency in the header and the instructions shown in the permit. The following should be completed by the permittee or authorized representative:

Resubmitted DMR: Check this box if this DMR is being re-submitted because there was information missing from or information that needed correction on a previously submitted DMR. The information that is being revised should be clearly noted on the re-submitted DMR (e.g. highlight, circle, etc.)
No Discharge From Site: Check this box if no discharge occurs and, as a result, there are no data or codes to be entered for all of the parameters on the DMR for the entire monitoring group number; however, if the monitoring group includes other monitoring locations (e.g., influent sampling), the "NOD" code should be used to individually denote those parameters for which there was no discharge.
Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Sample Measurement: Before filling in sample measurements in the table, check to see that the data collected correspond to the limit indicated on the DMR (i.e. interim or final) and that the data correspond to the monitoring group number in the header. Enter the data or calculated results for each parameter on this row in the non-shaded area above the limit. Be sure the result being entered corresponds to the appropriate statistical base code (e.g. annual average, monthly average, single sample maximum, etc.) and units. Data qualifier codes are not to be reported on Part A.
No. Ex.: Enter the number of sample measurements during the monitoring period that exceeded the permit limit for each parameter in the non-shaded area. If none, enter zero.
Frequency of Analysis: The shaded areas in this column contain the minimum number of times the measurement is required to be made according to the permit. Enter the actual number of times the measurement was made in the space above the shaded area.
Sample Type: The shaded areas in this column contain the type of sample (e.g. grab, composite, continuous) required by the permit. Enter the actual sample type that was taken in the space above the shaded area.
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comment and Explanation of Any Violations: Use this area to explain any exceedances, any upset or by-pass events, or other items which require explanation. If more space is needed, reference all attachments in this area.

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PART B - DAILY SAMPLE RESULTS

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Daily Monitoring Results: Transfer all analytical data from your facility's laboratory or a contract laboratory's data sheets for all day(s) that samples were collected. Record the data in the units indicated. Table 1 in Chapter 62-160, F.A.C., contains a complete list of all the data qualifier codes that your laboratory may use when reporting analytical results. However, when transferring numerical results onto Part B of the DMR, only the following data qualifier codes should be used and an explanation provided where appropriate.

CODE	DESCRIPTION/INSTRUCTIONS
<	The compound was analyzed for but not detected.
A	Value reported is the mean (average) of two or more determinations.
J	Estimated value, value not accurate.
Q	Sample held beyond the actual holding time.
Y	Laboratory analysis was from an unpreserved or improperly preserved sample.

To calculate the monthly average, add each reported value to get a total. For flow, divide this total by the number of days in the month. For all other parameters, divide the total by the number of observations.
Plant Staffing: List the name, certificate number, and class of all state certified operators operating the facility during the monitoring period. Use additional sheets as necessary.

PART D - GROUND WATER MONITORING REPORT

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Date Sample Obtained: Enter the date the sample was taken. Also, check whether or not the well was purged before sampling.
Time Sample Obtained: Enter the time the sample was taken.
Sample Measurement: Record the results of the analysis. If the result was below the minimum detection limit, indicate that. Data qualifier codes are not to be reported on Part D.
Detection Limits: Record the detection limits of the analytical methods used.
Analysis Method: Indicate the analytical method used. Record the method number from Chapter 62-160 or Chapter 62-601, F.A.C., or from other sources.
Sampling Equipment Used: Indicate the procedure used to collect the sample (e.g. airlift, bucket/bailer, centrifugal pump, etc.)
Samples Filtered: Indicate whether the sample obtained was filtered by laboratory (L), filtered in field (F), or unfiltered (N).
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comments and Explanation: Use this space to make any comments on or explanations of results that are unexpected. If more space is needed, reference all attachments in this area.

SPECIAL INSTRUCTIONS FOR LIMITED WET WEATHER DISCHARGES

Flow (Limited Wet Weather Discharge): Enter the measured average flow rate during the period of discharge or divide gallons discharged by duration of discharge (converted into days). Record in million gallons per day (MGD).
Flow (Upstream): Enter the average flow rate in the receiving stream upstream from the point of discharge for the period of discharge. The average flow rate can be calculated based on two measurements; one made at the start and one made at the end of the discharge period. Measurements are to be made at the upstream gauging station described in the permit.
Actual Stream Dilution Ratio: To calculate the Actual Stream Dilution Ratio, divide the average upstream flow rate by the average discharge flow rate. Enter the Actual Stream Dilution Ratio accurate to the nearest 0.1.
No. of Days the SDF > Stream Dilution Ratio: For each day of discharge, compare the minimum Stream Dilution Factor (SDF) from the permit to the calculated Stream Dilution Ratio. On Part B of the DMR, enter an asterisk (*) if the SDF is greater than the Stream Dilution Ratio on any day of discharge. On Part A of the DMR, add up the days with an "*" and record the total number of days the Stream Dilution Factor was greater than the Stream Dilution Ratio.
$CBOD_5$: Enter the average $CBOD_5$ of the reclaimed water discharged during the period shown in duration of discharge.
TKN: Enter the average TKN of the reclaimed water discharged during the period shown in duration of discharge.
Actual Rainfall: Enter the actual rainfall for each day on Part B. Enter the actual cumulative rainfall to date for this calendar year and the actual total monthly rainfall on Part A. The cumulative rainfall to date for this calendar year is the total amount of rain, in inches, that has been recorded since January 1 of the current year through the month for which this DMR contains data.
Rainfall During Average Rainfall Year: On Part A, enter the total monthly rainfall during the average rainfall year and the cumulative rainfall for the average rainfall year. The cumulative rainfall for the average rainfall year is the amount of rain, in inches, which fell during the average rainfall year from January through the month for which this DMR contains data.
No. of Days LWWD Activated During Calendar Year: Enter the cumulative number of days that the limited wet weather discharge was activated since January 1 of the current year.
Reason for Discharge: Attach to the DMR a brief explanation of the factors contributing to the need to activate the limited wet weather discharge.

DRAFT



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 14
PARTY: MWS-10
DESCRIPTION: Photo of Manatee Calf at Sea World Rehabilitation Center

Schedule 1A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period True-Up Amount
January 2019 - December 2019

Line No.		Period Amount ($)
1	End of Period Actual Total True-Up for the Period January 2019 - December 2019 (Schedule 2A, Line 5 + 6 + 9)	10,501,410
2	Estimated/Actual True-up Amount approved for the period January 2019 - December 2019 (FPSC Order No. PSC-2019-0500-FOF-EI)	4,609,567
3	Current Period True-Up Amount to be Refunded/(Recovered) in the Period January 2021 - December 2021 (Lines 1 - 2)	5,891,843

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 15
PARTY: RLH-1
DESCRIPTION: Environmental Cost Recovery Final True-up January 2019 - December 2019 Commission Forms 42-1A throug...

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)

January 2019 - December 2019
Calculation of the Current Period Estimated True-Up Amount
Current Period True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	ECRC Revenues (Net of Revenue Taxes)	13,657,836	10,323,250	11,590,808	11,609,091	15,888,312	17,740,586	19,067,936	18,248,759	17,848,622	14,426,385	11,140,882	12,316,985	173,859,453
2	True-Up Provision (Order No. PSC-2018-0594-FOF-EI)	1,051,379	1,051,384	1,051,384	1,051,384	1,051,384	1,051,384	1,051,384	1,051,384	1,051,384	1,051,384	1,051,384	1,051,384	12,616,603
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	14,709,215	11,374,634	12,642,192	12,660,475	16,939,696	18,791,970	20,119,320	19,300,143	18,900,006	15,477,769	12,192,266	13,368,369	186,476,056
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5A, Line 9)	3,049,120	1,766,665	2,466,911	1,741,240	2,502,734	2,158,170	2,631,490	1,645,808	2,846,122	2,283,134	1,820,854	1,778,567	26,690,815
	b Capital Investment Projects (Schedule 7A, Line 9)	12,457,436	12,459,241	12,496,274	12,531,591	12,530,598	12,519,701	12,559,382	12,563,487	12,566,666	12,577,162	12,626,443	12,569,421	150,457,402
	c **Total Jurisdictional ECRC Costs**	15,506,556	14,225,906	14,963,185	14,272,831	15,033,332	14,677,871	15,190,872	14,209,295	15,412,788	14,860,297	14,447,297	14,347,988	177,148,216
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	(797,341)	(2,851,271)	(2,320,992)	(1,612,356)	1,906,364	4,114,099	4,928,448	5,090,848	3,487,218	617,472	(2,255,031)	(979,619)	9,327,840
6	Interest Provision (Schedule 3A, Line 10)	27,353	21,566	14,519	8,431	6,475	10,188	15,970	21,862	26,639	25,617	20,940	17,845	217,405
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2018	11,333,073	9,511,706	5,630,617	2,272,760	(382,550)	478,905	3,551,809	7,444,843	11,506,169	13,968,642	13,560,348	10,976,177	11,333,073
	b Final True-Up from January 2017 - December 2017 (Order No. PSC-2018-0594-FOF-EI)	3,179,666	3,179,666	3,179,666	3,179,666	3,179,666	3,179,666	3,179,666	3,179,666	3,179,666	3,179,666	3,179,666	3,179,666	3,179,666
8	True-Up Collected/(Refunded) (see Line 2)	(1,051,379)	(1,051,384)	(1,051,384)	(1,051,384)	(1,051,384)	(1,051,384)	(1,051,384)	(1,051,384)	(1,051,384)	(1,051,384)	(1,051,384)	(1,051,384)	(12,616,603)
9	Adjustments											701,304	254,861	956,165
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8 + 9)	12,691,372	8,810,283	5,452,426	2,797,116	3,658,571	6,731,475	10,624,509	14,685,835	17,148,308	16,740,014	14,155,843	12,397,545	12,397,545

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2019 - December 2019

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Beg. True-Up Amount (Schedule 2A, Lines 7a + 7b)	14,512,739	12,691,372	8,810,283	5,452,426	2,797,116	3,658,571	6,731,475	10,624,509	14,685,835	17,148,308	16,740,014	14,155,843	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2A, Lines 5 + 8)	12,664,019	8,788,717	5,437,907	2,788,686	3,652,096	6,721,287	10,608,539	14,663,973	17,121,669	16,714,397	13,433,598	12,124,840	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	27,176,758	21,480,090	14,248,190	8,241,112	6,449,213	10,379,858	17,340,013	25,288,482	31,807,504	33,862,705	30,173,612	26,280,683	
4	Average True-Up Amount (Line 3 x 1/2)	13,588,379	10,740,045	7,124,095	4,120,556	3,224,606	5,189,929	8,670,007	12,644,241	15,903,752	16,931,352	15,086,806	13,140,341	
5	Interest Rate (First Day of Reporting Business Month)	0.02420	0.02410	0.02480	0.02430	0.02390	0.02320	0.0210	0.0205	0.0197	0.0166	0.0167	0.0159	
6	Interest Rate (First Day of Subsequent Business Month)	0.02410	0.02410	0.02410	0.02480	0.02430	0.02390	0.02320	0.0210	0.0205	0.0197	0.0166	0.0167	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.04830	0.04820	0.04890	0.04910	0.04820	0.04710	0.0442	0.0415	0.0402	0.0363	0.0333	0.0326	
8	Average Interest Rate (Line 7 x 1/2)	0.02415	0.02410	0.02445	0.02455	0.02410	0.02355	0.02210	0.02075	0.02010	0.01815	0.01665	0.01630	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.00201	0.00201	0.00204	0.00205	0.00201	0.00196	0.00184	0.00173	0.00168	0.00151	0.00139	0.00136	
10	Interest Provision for the Month (Line 4 x Line 9)	27,353	21,566	14,519	8,431	6,475	10,188	15,970	21,862	26,639	25,617	20,940	17,845	217,405

Schedule 4A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2019 - December 2019

Variance Report of O & M Activities
(in Dollars)

Line			(1) Final Actual	(2) Actual / Estimated	(3) Variance Amount	(4) Variance Percent
1		Description of O & M Activities				
	.1	Sulfur	0	0	0	0.0 %
	.2	Air Emission Fees	245,769	216,023	29,746	13.8 %
	.3	Title V	167,394	260,325	(92,931)	(35.7) %
	.4	Asbestos Fees	500	1,207	(707)	(59) %
	.5	Emission Monitoring	753,220	770,225	(17,006)	(2.2) %
	.6	General Water Quality	1,714,707	1,967,116	(252,409)	(12.8) %
	.7	Groundwater Contamination Investigation	1,825,217	2,270,787	(445,570)	(19.6) %
	.8	State NPDES Administration	34,877	42,376	(7,500)	(17.7) %
	.9	Lead and Copper Rule	0	0	0	0.0 %
	.10	Env Auditing/Assessment	6,686	16,005	(9,318)	(58.2) %
	.11	General Solid & Hazardous Waste	956,015	1,026,680	(70,664)	(6.9) %
	.12	Above Ground Storage Tanks	117,386	121,715	(4,329)	(3.6) %
	.13	Low NOx	0	0	0	0.0 %
	.14	Ash Pond Diversion Curtains	0	0	0	0.0 %
	.15	Mercury Emissions	0	0	0	0.0 %
	.16	Sodium Injection	0	0	0	0.0 %
	.17	Gulf Coast Ozone Study	0	0	0	0.0 %
	.18	SPCC Substation Project	0	0	0	0.0 %
	.19	FDEP NOx Reduction Agreement	253,453	505,192	(251,739)	(49.8) %
	.20	Air Quality Compliance Program	16,864,010	19,145,434	(2,281,425)	(11.9) %
	.21	MACT ICR	0	0	0	0.0 %
	.22	Crist Water Conservation	14,030	390,903	(376,873)	(96.4) %
	.23	Coal Combustion Residual	4,814,078	4,204,267	609,810	14.5 %
	.24	Smith Water Conservation	152,397	165,289	(12,892)	(7.8) %
	.25	Mercury Allowances	0	0	0	0.0 %
	.26	Annual NOx Allowances	1,257	1,945	(688)	(35.4) %
	.27	Seasonal NOx Allowances	5,264	5,103	161	3.2 %
	.28	SO2 Allowances	11,476	22,643	(11,167)	(49.3) %
	.29	Scherer/Flint Credit - Energy	(517,559)	(472,723)	(44,836)	9.5 %
	.30	Scherer/Flint Credit - Demand	(6,925)	(8,700)	1,775	(20.4) %
2		Total O & M Activities	27,413,252	30,651,813	(3,238,561)	(10.6) %
3		Recoverable Costs Allocated to Energy	17,784,284	20,454,167	(2,669,883)	(13.1) %
4		Recoverable Costs Allocated to Demand	9,628,968	10,197,646	(568,678)	(5.6) %

Notes:
Column (1) is the End of Period Totals on Schedule 5A
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-2019-0500-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019

O & M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
. 1	Sulfur	0		0	0	0	0	0	0	0	0	0	0	0	0	0
. 2	Air Emission Fees	11,746	3,542	105,541	(2,602)	3,858	3,540	3,772	4,159	103,157	3,086	2,897	3,072	245,769	0	245,769
. 3	Title V	330	14,463	28,848	3,805	33,636	11,566	14,133	10,757	8,187	11,343	14,095	16,232	167,394	0	167,394
. 4	Asbestos Fees	0	0	1,000	707	5,639	(6,139)	0	0	52,582	(51,500)	0	(1,789)	500	500	0
. 5	Emission Monitoring	36,406	39,617	134,947	93,046	64,693	30,258	36,107	50,515	92,065	51,001	75,589	48,975	753,220	0	753,220
. 6	General Water Quality	114,600	234,318	123,757	87,089	133,024	20,738	91,731	57,983	144,082	291,536	257,577	158,270	1,714,707	1,714,707	0
. 7	Groundwater Contamination Investigation	876,056	(523,369)	179,910	342,240	35,487	288,452	202,865	7,309	317,676	63,104	(59,878)	95,366	1,825,217	1,825,217	0
. 8	State NPDES Administration	1,530	3,994	5,884	7,572	3,534	(14,638)	2,543	7,330	5,070	3,102	3,871	5,084	34,877	34,877	0
. 9	Lead & Copper Rule	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 10	Environmental Auditing/Assessment	0	0	0	0	78	927	0	0	0	0	0	5,682	6,686	6,686	0
. 11	General Solid & Hazardous Waste	18,325	58,250	68,226	84,109	128,456	95,895	122,075	74,199	53,445	63,946	66,849	122,240	956,015	956,015	0
. 12	Above Ground Storage Tanks	11,350	76,414	21,109	4,123	5,412	41,742	10,944	10,347	6,789	7,693	(37,331)	(41,206)	117,386	117,386	0
. 13	Low NOx	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 14	Ash Pond Diversion Curtains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 15	Mercury Emissions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 16	Sodium Injection	8,725	0	0	0	0	(8,725)	0	0	0	0	0	0	0	0	0
. 17	Gulf Coast Ozone Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 18	SPCC Substation Project	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 19	FDEP NOx Reduction Agreement	0	46,834	88,606	5,170	0	44,579	51,154	(40,102)	9,685	18,504	16,149	12,877	253,453	0	253,453
. 20	Air Quality Compliance Program	1,475,042	1,941,433	1,215,486	704,313	1,651,263	1,712,030	1,448,394	1,281,023	1,800,475	1,372,402	1,166,577	1,095,574	16,864,010	0	16,864,010
. 21	MACT ICR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 22	Crist Water Conservation	0	7,780	10,569	435	0	0	0	(4,753)	0	0	0	0	14,030	14,030	0
. 23	Coal Combustion Residuals	602,106	(31,715)	594,353	428,491	536,085	76,424	758,861	256,393	354,010	515,194	397,643	326,232	4,814,078	4,814,078	0
. 24	Smith Water Conservation	0	14,868	49,780	50,873	46,240	(41,972)	2,267	6,739	7,070	10,128	390	6,015	152,397	152,397	0
. 25	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 26	Annual NOx Allowances	0	0	371.88	0	0	0	525	0	0	361	0	0	1,257	0	1,257
. 27	Seasonal NOx Allowances	0	0	0.00	0	0	0	1,969	0	0	3,295	0	0	5,264	0	5,264
. 28	SO2 Allowances	0	0	2,204	0	0	(88)	2,715	(15)	(15)	6,703	(15)	(15)	11,476	0	11,476
. 29	Scherer/Flint Credit - Energy	(20,906)	(74,084)	(95,667)	(17,324)	(77,547)	(42,133)	(48,142)	(32,139)	(31,901)	(24,564)	(31,330)	(21,822)	(517,559)	0	(517,559)
. 30	Scherer/Flint Credit - Demand	(75)	(35)	(872)	(3,201)	488	(1,388)	197	(430)	(593)	(103)	(85)	(829)	(6,925)	(6,925)	0
2	Total of O & M Activities	3,135,234	1,812,311	2,534,054	1,788,847	2,570,345	2,211,067	2,702,109	1,689,314	2,921,783	2,345,230	1,873,000	1,829,957	27,413,252	9,628,968	17,784,284
3	Recoverable Costs Allocated to Energy	1,511,342	1,971,805	1,480,337	786,409	1,675,903	1,751,026	1,510,625	1,274,197	1,981,652	1,442,130	1,243,963	1,154,894	17,784,284		
4	Recoverable Costs Allocated to Demand	1,623,892	(159,494)	1,053,717	1,002,439	894,442	460,041	1,191,483	415,116	940,131	903,100	629,037	675,063	9,628,968		
5	Retail Energy Jurisdictional Factor	0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045			
6	Retail Demand Jurisdictional Factor	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277			
7	Jurisdictional Energy Recoverable Costs (A)	1,470,976	1,921,665	1,442,879	767,043	1,633,490	1,711,089	1,473,573	1,242,386	1,932,477	1,405,477	1,209,539	1,122,521	17,333,117		
8	Jurisdictional Demand Recoverable Costs (B)	1,578,143	(155,001)	1,024,031	974,198	869,244	447,081	1,157,916	403,422	913,645	877,658	611,315	656,045	9,357,698		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	3,049,120	1,766,665	2,466,911	1,741,240	2,502,734	2,158,170	2,631,490	1,645,808	2,846,122	2,283,134	1,820,854	1,778,567	26,690,815		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Schedule 6A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2019 - December 2019

Variance Report of Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		(1) Final Actual	(2) Actual/ Estimated	(3) Variance Amount	(4) Variance Percent	
1	Description of Investment Projects					
.1	Air Quality Assurance Testing	7,603	8,579	(975)	(11.4)	%
.2	Crist 5, 6 & 7 Precipitator Projects	3,794,607	3,794,499	108	0.0	%
.3	Crist 7 Flue Gas Conditioning	104,096	104,137	(40)	(0.0)	%
.4	Low NOx Burners, Crist 6 & 7	1,769,643	1,775,014	(5,371)	(0.3)	%
.5	CEMS - Plants Crist, & Daniel	541,960	541,040	920	0.2	%
.6	Substation Contamination Remediation	369,501	404,453	(34,953)	(8.6)	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	13,034	13,027	7	0.1	%
.8	Crist Cooling Tower Cell	36,931	36,945	(14)	(0.0)	%
.9	Crist Dechlorination System	24,083	24,061	22	0.1	%
.10	Crist Diesel Fuel Oil Remediation	1,071	3,889	(2,818)	(72.5)	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	5,093	5,087	6	0.1	%
.12	Crist IWW Sampling System	2,966	2,962	4	0.1	%
.13	Sodium Injection System	21,662	21,647	15	0.1	%
.14	Smith Stormwater Collection System	174,056	173,979	77	0.0	%
.15	Smith Waste Water Treatment Facility	59,746	61,919	(2,173)	(3.5)	%
.16	Daniel Ash Management Project	1,289,696	1,290,480	(784)	(0.1)	%
.17	Smith Water Conservation	2,314,430	2,335,904	(21,474)	(0.9)	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	10,684,947	10,738,513	(53,566)	(0.5)	%
.20	SPCC Compliance	76,344	76,296	48	0.1	%
.21	Crist Common FTIR Monitor	850	4,546	(3,696)	(81.3)	%
.22	Precipitator Upgrades for CAM Compliance	1,135,925	1,141,221	(5,296)	(0.5)	%
.23	Plant Groundwater Contamination	0	0	0	0.0	%
.24	Crist Water Conservation	1,775,946	1,780,736	(4,790)	(0.3)	%
.25	Plant NPDES Permit Compliance Projects	781,176	795,177	(14,001)	(1.8)	%
.26	Air Quality Compliance Program	126,073,487	126,223,523	(150,036)	(0.1)	%
.27	General Water Quality	92,612	102,081	(9,469)	(9.3)	%
.28	Coal Combustion Residual	3,917,862	3,944,729	(26,867)	(0.7)	%
.29	Steam Electric Effluent Limitations Guidelines	603,846	604,453	(607)	(0.1)	%
.30	316(b) Cooling Water Intake Structure Regulation	1,422	31,863	(30,441)	(95.5)	%
.31	Mercury Allowances	0	0	0	0.0	%
.32	Annual NOx Allowances	445	445	(0)	(0.0)	%
.33	Seasonal NOx Allowances	457	4,592	(4,135)	(90.0)	%
.34	SO2 Allowances	438,090	438,037	53	0.0	%
.35	Regulatory Asset Smith Units 1 & 2	2,756,588	2,757,082	(494)	(0.0)	%
.36	Scherer/Flint Credit - Energy	(314,176)	(314,942)	765	0.2	%
.37	Scherer/Flint Credit - Demand	(3,770,115)	(3,779,299)	9,184	0.2	%
2	Total Investment Projects - Recoverable Costs	154,785,887	155,146,676	(360,790)	(0.2)	%
3	Recoverable Costs Allocated to Energy	11,906,607	11,934,360	(27,753)	(0.2)	%
4	Recoverable Costs Allocated to Demand	142,879,280	143,212,317	(333,037)	(0.2)	%

Notes:
Column (1) is the End of Period Totals on Schedule 7A
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-2019-0500-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
. 1	Air Quality Assurance Testing	0	0	0	0	242	484	488	488	1,485	1,479	1,473	1,463	7,603	7,018	585
. 2	Crist 5, 6 & 7 Precipitator Projects	318,853	318,213	317,572	316,932	316,291	315,559	316,737	316,091	315,445	314,798	315,271	312,844	3,794,607	3,502,714	291,893
. 3	Crist 7 Flue Gas Conditioning	8,641	8,641	8,641	8,641	8,641	8,641	8,722	8,722	8,722	8,722	8,722	8,645	104,096	96,089	8,007
. 4	Low NOx Burners, Crist 6 & 7	148,946	148,680	148,414	148,148	147,881	147,169	147,400	147,133	146,866	146,599	146,777	145,629	1,769,643	1,633,517	136,126
. 5	CEMS - Plants Crist & Daniel	45,430	45,343	45,257	45,170	45,084	45,064	45,318	45,231	45,143	45,056	45,104	44,761	541,960	500,271	41,689
. 6	Substation Contamination Remediation	28,145	29,427	30,483	31,080	31,310	31,540	31,346	30,217	29,813	30,604	32,006	33,531	369,501	341,077	28,423
. 7	Raw Water Well Flowmeters - Plants Crist & Smith	1,099	1,096	1,093	1,090	1,087	1,084	1,087	1,084	1,081	1,078	1,081	1,073	13,034	12,032	1,003
. 8	Crist Cooling Tower Cell	3,065	3,065	3,065	3,065	3,065	3,065	3,094	3,094	3,094	3,094	3,094	3,067	36,931	34,090	2,841
. 9	Crist Dechlorination System	2,042	2,035	2,027	2,020	2,013	2,006	2,005	1,998	1,991	1,983	1,989	1,975	24,083	22,231	1,853
. 10	Crist Diesel Fuel Oil Remediation	331	330	328	327	326	107	(112)	(113)	(113)	(114)	(113)	(112)	1,071	989	82
. 11	Crist Bulk Tanker Unloading Secondary Containment	434	432	430	428	426	425	423	421	420	418	419	416	5,093	4,702	392
. 12	Crist IWW Sampling System	253	252	251	249	248	247	247	245	244	243	244	242	2,966	2,738	228
. 13	Sodium Injection System	1,830	1,825	1,819	1,814	1,808	1,803	1,806	1,800	1,795	1,789	1,793	1,780	21,662	19,996	1,666
. 14	Smith Stormwater Collection System	14,825	14,763	14,700	14,638	14,576	14,514	14,486	14,424	14,361	14,298	14,281	14,189	174,056	160,667	13,389
. 15	Smith Waste Water Treatment Facility	3,921	4,546	5,172	5,170	5,166	5,162	5,199	5,110	5,020	5,019	5,108	5,152	59,746	55,150	4,596
. 16	Daniel Ash Management Project	108,519	108,304	108,088	107,873	107,657	107,398	107,588	107,371	107,154	106,937	106,719	106,088	1,289,696	1,190,488	99,207
. 17	Smith Water Conservation	184,305	184,962	191,186	196,358	195,661	195,106	195,823	195,262	194,642	194,222	194,152	192,750	2,314,430	2,136,397	178,033
. 18	Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 19	Crist FDEP Agreement for Ozone Attainment	902,730	900,983	899,728	897,600	894,979	889,270	888,084	885,747	883,437	881,134	883,646	877,610	10,684,947	9,863,028	821,919
. 20	SPCC Compliance	6,448	6,429	6,410	6,392	6,373	6,354	6,364	6,345	6,327	6,308	6,320	6,274	76,344	70,471	5,873
. 21	Crist Common FTIR Monitor	385	384	382	381	380	94	(193)	(193)	(193)	(193)	(193)	(191)	850	785	65
. 22	Precipitator Upgrades for CAM Compliance	96,358	96,092	95,826	95,559	95,293	94,565	94,287	94,021	93,754	93,487	93,682	93,000	1,135,925	1,048,546	87,379
. 23	Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 24	Crist Water Conservation	149,277	149,003	149,148	149,186	148,805	147,987	147,938	147,559	147,180	146,800	147,078	145,986	1,775,946	1,639,334	136,611
. 25	Plant NPDES Permit Compliance Projects	50,625	53,778	55,961	60,022	62,516	61,795	62,046	69,315	76,541	76,337	76,400	75,840	781,176	721,086	60,090
. 26	Air Quality Compliance Program	10,592,584	10,570,683	10,551,918	10,540,562	10,525,406	10,494,398	10,510,339	10,491,996	10,472,787	10,455,173	10,468,417	10,399,224	126,073,487	116,375,527	9,697,961
. 27	General Water Quality	7,471	7,455	7,439	7,423	7,407	7,542	7,570	7,478	7,538	7,522	8,343	9,422	92,612	85,488	7,124
. 28	Coal Combustion Residuals	150,755	171,986	222,750	265,919	288,445	321,175	349,719	372,867	393,945	429,036	464,801	486,464	3,917,862	3,616,488	301,374
. 29	Steam Electric Effluent Limitations Guidelines	50,153	50,045	49,938	49,830	49,723	49,615	49,796	49,688	49,579	49,646	51,530	54,304	603,846	557,397	46,450
. 30	316(B) Intake Structure Regulation	0	0	0	0	18	39	48	57	66	72	77	1,045	1,422	1,312	109
. 31	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 32	Annual NOx Allowances	40	40	39	38	38	38	37	36	36	35	34	33	445	411	34
. 33	Seasonal NOx Allowances	47	47	47	47	47	47	42	36	36	27	17	17	457	422	35
. 34	SO2 Allowances	36,389	36,389	36,383	36,376	36,376	36,377	36,710	36,702	36,702	36,682	36,663	36,341	438,090	404,391	33,699
. 35	Regulatory Asset Smith Units 1 & 2	233,044	232,361	231,677	230,994	230,311	229,627	229,978	229,288	228,598	227,909	227,219	225,583	2,756,588	2,544,543	212,045
. 36	Scherer/Flint Credit - Energy	(25,374)	(25,381)	(25,428)	(25,545)	(25,898)	(26,241)	(26,514)	(26,547)	(26,613)	(26,712)	(26,938)	(26,984)	(314,176)	0	(314,176)
. 37	Scherer/Flint Credit - Demand	(304,492)	(304,569)	(305,138)	(306,538)	(310,779)	(314,891)	(318,171)	(318,565)	(319,356)	(320,548)	(323,259)	(323,810)	(3,770,115)	(3,770,115)	0
2	Total Investment Projects - Recoverable Costs	12,817,080	12,817,637	12,855,609	12,891,250	12,890,924	12,877,166	12,919,739	12,924,409	12,927,525	12,938,939	12,991,957	12,933,651	154,785,887	142,879,280	11,906,607
3	Recoverable Costs Allocated to Energy	985,929	985,972	988,893	991,635	991,610	990,551	993,826	994,185	994,425	995,303	999,381	994,896	11,906,607		
4	Recoverable Costs Allocated to Demand	11,831,150	11,831,665	11,866,716	11,899,615	11,899,315	11,886,615	11,925,913	11,930,224	11,933,100	11,943,636	11,992,576	11,938,755	142,879,280		
5	Retail Energy Jurisdictional Factor	0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045			
6	Retail Demand Jurisdictional Factor	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277			
7	Jurisdictional Energy Recoverable Costs (B)	959,596	960,900.68	963,871	967,215	966,514	967,959	969,450	969,365	969,748	970,006	971,725	967,009	11,603,360		
8	Jurisdictional Demand Recoverable Costs (C)	11,497,840	11,498,340	11,532,403	11,564,376	11,564,084	11,551,742	11,589,932	11,594,122	11,596,917	11,607,156	11,654,718	11,602,413	138,854,042		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	12,457,436	12,459,241	12,496,274	12,531,591	12,530,598	12,519,701	12,559,382	12,563,487	12,566,666	12,577,162	12,626,443	12,569,421	150,457,402		

Notes:
(A) Pages 1-30 of Schedule 8A, Line 9, Pages 31-34 of Schedule 8A, Line 6, Page 35, Line 7, Schedule 9A, Line 11 - Line 10 x 24%.
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	83,954	0	0	0	0	0	0	0	83,954
	b Clearings to Plant		0	0	0	0	0	0	0	83,954	0	0	0	0	83,954
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	83,954	83,954	83,954	83,954	83,954	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	(999)	(1,999)	(2,998)	(3,998)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	83,954	83,954	83,954	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	83,954	83,954	83,954	83,954	82,954	81,955	80,956	79,956	
6	Average Net Investment		0	0	0	0	41,977	83,954	83,954	83,954	83,454	82,455	81,455	80,456	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	194	388	391	391	388	384	379	370	2,885
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	48	96	98	98	97	96	95	93	720
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	999	999	999	999	3,998
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	242	484	488	488	1,485	1,479	1,473	1,463	7,603
	a Recoverable Costs Allocated to Energy		0	0	0	0	19	37	38	38	114	114	113	113	585
	b Recoverable Costs Allocated to Demand		0	0	0	0	223	447	451	451	1,371	1,365	1,360	1,351	7,018
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	18	36	37	37	111	111	110	109	570
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	217	434	438	438	1,332	1,327	1,322	1,313	6,821
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	235	470	475	475	1,443	1,438	1,432	1,422	7,390

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1244 has a 7-year amortization period. PE 1006 is fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	
3	Less: Accumulated Depreciation (C)	2,421,657	2,310,521	2,199,386	2,088,251	1,977,116	1,865,981	1,754,879	1,643,811	1,532,742	1,421,674	1,310,605	1,198,415	1,086,225	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	36,098,980	35,987,844	35,876,709	35,765,574	35,654,439	35,543,304	35,411,966	35,300,897	35,189,829	35,078,760	34,967,692	34,855,502	34,743,311	
6	Average Net Investment		36,043,412	35,932,277	35,821,142	35,710,007	35,598,871	35,477,635	35,356,431	35,245,363	35,134,295	35,023,226	34,911,597	34,799,407	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		166,557	166,043	165,529	165,016	164,502	163,942	164,584	164,067	163,550	163,033	162,513	160,216	1,969,554
	b Debt Component (Line 6 x Debt Component x 1/12)		41,162	41,035	40,908	40,781	40,654	40,515	41,084	40,955	40,826	40,697	40,567	40,437	489,621
8	Investment Expenses														
	a Depreciation (E)		111,135	111,135	111,135	111,135	111,135	111,102	111,068	111,068	111,068	111,068	112,190	112,190	1,335,432
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		318,853	318,213	317,572	316,932	316,291	315,559	316,737	316,091	315,445	314,798	315,271	312,844	3,794,607
	a Recoverable Costs Allocated to Energy		24,527	24,478	24,429	24,379	24,330	24,274	24,364	24,315	24,265	24,215	24,252	24,065	291,893
	b Recoverable Costs Allocated to Demand		294,326	293,735	293,144	292,553	291,961	291,286	292,372	291,776	291,180	290,583	291,019	288,779	3,502,714
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		23,872	23,855	23,811	23,779	23,714	23,720	23,767	23,708	23,663	23,600	23,580	23,390	284,460
13	Retail Demand-Related Recoverable Costs (I)		286,034	285,460	284,885	284,311	283,736	283,079	284,136	283,556	282,976	282,397	282,821	280,643	3,404,034
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		309,906	309,315	308,696	308,090	307,451	306,800	307,902	307,264	306,639	305,997	306,401	304,034	3,688,494

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $20,237 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
6	Average Net Investment		1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D		6,928	6,928	6,928	6,928	6,928	6,928	6,979	6,979	6,979	6,979	6,979	6,903	83,370
	b Debt Component (Line 6 x Debt Component x 1/12)		1,712	1,712	1,712	1,712	1,712	1,712	1,742	1,742	1,742	1,742	1,742	1,742	20,727
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,641	8,641	8,641	8,641	8,641	8,641	8,722	8,722	8,722	8,722	8,722	8,645	104,096
	a Recoverable Costs Allocated to Energy		665	665	665	665	665	665	671	671	671	671	671	665	8,007
	b Recoverable Costs Allocated to Demand		7,976	7,976	7,976	7,976	7,976	7,976	8,051	8,051	8,051	8,051	8,051	7,980	96,089
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		647	648	648	648	648	650	654	654	654	654	652	646	7,803
13	Retail Demand-Related Recoverable Costs (I)		7,751	7,751	7,751	7,751	7,751	7,751	7,824	7,824	7,824	7,824	7,824	7,755	93,382
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,398	8,399	8,399	8,400	8,399	8,401	8,478	8,478	8,478	8,478	8,476	8,402	101,185

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	119	0	0	0	0	0	0	0	0	0	119
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,626,375	13,626,375	13,626,375	13,626,493	13,626,493	13,626,493	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	
3	Less: Accumulated Depreciation (C)	4,224,493	4,178,289	4,132,085	4,085,881	4,039,677	3,993,472	3,947,430	3,901,551	3,855,672	3,809,793	3,763,914	3,717,588	3,671,263	
4	CWIP - Non Interest Bearing	119	119	119	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4) (A)	17,850,987	17,804,783	17,758,579	17,712,374	17,666,170	17,619,965	17,475,362	17,429,483	17,383,604	17,337,724	17,291,845	17,245,520	17,199,195	
6	Average Net Investment		17,827,885	17,781,681	17,735,476	17,689,272	17,643,068	17,547,664	17,452,422	17,406,543	17,360,664	17,314,785	17,268,683	17,222,357	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		82,383	82,169	81,956	81,742	81,529	81,088	81,241	81,027	80,814	80,600	80,386	79,292	974,226
	b Debt Component (Line 6 x Debt Component x 1/12)		20,359	20,307	20,254	20,201	20,148	20,039	20,280	20,226	20,173	20,120	20,066	20,012	242,187
8	Investment Expenses														
	a Depreciation (E)		44,493	44,493	44,493	44,493	44,493	44,330	44,168	44,168	44,168	44,168	44,614	44,614	532,693
	b Amortization (F)		1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	20,537
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		148,946	148,680	148,414	148,148	147,881	147,169	147,400	147,133	146,866	146,599	146,777	145,629	1,769,643
	a Recoverable Costs Allocated to Energy		11,457	11,437	11,416	11,396	11,375	11,321	11,338	11,318	11,297	11,277	11,291	11,202	136,126
	b Recoverable Costs Allocated to Demand		137,489	137,243	136,997	136,752	136,506	135,848	136,061	135,815	135,569	135,322	135,487	134,427	1,633,517
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		11,151	11,146	11,128	11,115	11,088	11,062	11,060	11,035	11,017	10,990	10,978	10,888	132,660
13	Retail Demand-Related Recoverable Costs (I)		133,615	133,377	133,138	132,899	132,660	132,021	132,228	131,989	131,749	131,510	131,670	130,640	1,587,497
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		144,767	144,523	144,265	144,014	143,748	143,084	143,289	143,024	142,767	142,500	142,648	141,528	1,720,157

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $98,562 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Portions of PE 1236 have a 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist & Daniel

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	5,740	0	0	0	0	0	0	5,740
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	
3	Less: Accumulated Depreciation (C)	447,258	432,247	417,236	402,224	387,213	372,201	357,170	342,118	327,067	312,016	296,965	281,777	266,590	
4	CWIP - Non Interest Bearing	5,740	5,740	5,740	5,740	5,740	5,740	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	5,143,598	5,128,587	5,113,575	5,098,564	5,083,552	5,068,541	5,069,953	5,054,901	5,039,850	5,024,799	5,009,748	4,994,560	4,979,373	
6	Average Net Investment		5,136,092	5,121,081	5,106,069	5,091,058	5,076,046	5,069,247	5,062,427	5,047,376	5,032,324	5,017,273	5,002,154	4,986,966	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D		23,734	23,665	23,595	23,526	23,456	23,425	23,566	23,496	23,425	23,355	23,285	22,960	281,488
	b Debt Component (Line 6 x Debt Component x 1/12)		5,865	5,848	5,831	5,814	5,797	5,789	5,883	5,865	5,848	5,830	5,813	5,795	69,977
8	Investment Expenses														
	a Depreciation (E)		15,011	15,011	15,011	15,011	15,011	15,031	15,051	15,051	15,051	15,051	15,187	15,187	180,669
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		819	819	819	819	819	819	819	819	819	819	819	819	9,827
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		45,430	45,343	45,257	45,170	45,084	45,064	45,318	45,231	45,143	45,056	45,104	44,761	541,960
	a Recoverable Costs Allocated to Energy		3,495	3,488	3,481	3,475	3,468	3,466	3,486	3,479	3,473	3,466	3,470	3,443	41,689
	b Recoverable Costs Allocated to Demand		41,935	41,855	41,775	41,696	41,616	41,598	41,832	41,751	41,671	41,590	41,634	41,318	500,271
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		3,401	3,399	3,393	3,389	3,380	3,387	3,401	3,392	3,386	3,378	3,374	3,347	40,628
13	Retail Demand-Related Recoverable Costs (I)		40,754	40,676	40,598	40,521	40,443	40,426	40,654	40,575	40,497	40,418	40,461	40,154	486,177
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		44,155	44,075	43,992	43,910	43,823	43,813	44,054	43,968	43,883	43,796	43,835	43,501	526,805

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $16,443 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Beginning Balances: Crist $4,106,227; Daniel $584,373. Ending Balances: Crist $4,086,636; Daniel $626,147.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PEs 1364, 1658 and 1283 are fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Substation Contamination Remediation

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		238,583	62,830	103,709	62,136	29,380	43,521	(129,728)	(120,989)	(652,451)	151,854	183,241	256,080	228,165
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	1,765,667	1,765,667
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	1,003,177	1,003,177
	d Other		0	155,463	56,548	(3,034)	3,433	15,578	(65,897)	(59,649)	706,471	77,993	91,294	(250,983)	727,218
2	Plant-in-Service/Depreciation Base (B)	2,483,333	2,483,333	2,483,333	2,483,333	2,483,333	2,483,333	2,483,333	2,483,333	2,483,333	2,483,333	2,483,333	2,483,333	3,245,823	
3	Less: Accumulated Depreciation (C)	(598,002)	(604,051)	(454,638)	(404,140)	(413,224)	(415,840)	(406,312)	(478,258)	(543,957)	156,465	228,408	313,682	1,058,872	
4	CWIP - Non Interest Bearing	1,832,401	2,070,984	2,133,814	2,237,523	2,299,659	2,329,039	2,372,560	2,242,832	2,121,843	1,469,392	1,621,246	1,804,487	294,900	
5	Net Investment (Lines 2 + 3 + 4) (A)	3,717,733	3,950,267	4,162,510	4,316,717	4,369,769	4,396,532	4,449,581	4,247,907	4,061,220	4,109,190	4,332,987	4,601,502	4,599,596	
6	Average Net Investment		3,834,000	4,056,388	4,239,613	4,343,243	4,383,151	4,423,056	4,348,744	4,154,563	4,085,205	4,221,089	4,467,245	4,600,549	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		17,717	18,745	19,591	20,070	20,255	20,439	20,243	19,339	19,017	19,649	20,795	21,181	237,041
	b Debt Component (Line 6 x Debt Component x 1/12)		4,378	4,632	4,842	4,960	5,006	5,051	5,053	4,828	4,747	4,905	5,191	5,346	58,939
8	Investment Expenses														
	a Depreciation (E)		6,050	6,050	6,050	6,050	6,050	6,050	6,050	6,050	6,050	6,050	6,020	7,004	73,521
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		28,145	29,427	30,483	31,080	31,310	31,540	31,346	30,217	29,813	30,604	32,006	33,531	369,501
	a Recoverable Costs Allocated to Energy		2,165	2,264	2,345	2,391	2,408	2,426	2,411	2,324	2,293	2,354	2,462	2,579	28,423
	b Recoverable Costs Allocated to Demand		25,980	27,163	28,138	28,689	28,901	29,114	28,935	27,892	27,520	28,250	29,544	30,952	341,077
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		2,107	2,206	2,285	2,332	2,347	2,371	2,352	2,266	2,236	2,294	2,394	2,507	27,699
13	Retail Demand-Related Recoverable Costs (I)		25,248	26,398	27,345	27,881	28,087	28,293	28,120	27,107	26,745	27,454	28,711	30,080	331,468
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		27,355	28,604	29,631	30,213	30,435	30,664	30,472	29,373	28,981	29,748	31,105	32,587	359,167

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1007 is fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	
3	Less: Accumulated Depreciation (C)	(44,911)	(45,406)	(45,901)	(46,396)	(46,891)	(47,385)	(47,880)	(48,375)	(48,870)	(49,365)	(49,860)	(50,359)	(50,859)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	105,038	104,544	104,049	103,554	103,059	102,564	102,069	101,575	101,080	100,585	100,090	99,590	99,090	
6	Average Net Investment		104,791	104,296	103,801	103,306	102,812	102,317	101,822	101,327	100,832	100,337	99,840	99,340	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		484	482	480	477	475	473	474	472	469	467	465	457	5,675
	b Debt Component (Line 6 x Debt Component x 1/12)		120	119	119	118	117	117	118	118	117	117	116	115	1,411
8	Investment Expenses														
	a Depreciation (E)		495	495	495	495	495	495	495	495	495	495	500	500	5,948
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,099	1,096	1,093	1,090	1,087	1,084	1,087	1,084	1,081	1,078	1,081	1,073	13,034
	a Recoverable Costs Allocated to Energy		85	84	84	84	84	83	84	83	83	83	83	83	1,003
	b Recoverable Costs Allocated to Demand		1,014	1,012	1,009	1,006	1,004	1,001	1,004	1,001	998	996	997	990	12,032
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		82	82	82	82	82	82	82	81	81	81	81	80	977
13	Retail Demand-Related Recoverable Costs (I)		986	983	981	978	975	973	975	973	970	967	969	962	11,693
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,068	1,065	1,062	1,060	1,057	1,054	1,057	1,054	1,051	1,048	1,050	1,042	12,670

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
6	Average Net Investment		531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,458	2,458	2,458	2,458	2,458	2,458	2,476	2,476	2,476	2,476	2,476	2,449	29,578
	b Debt Component (Line 6 x Debt Component x 1/12)		607	607	607	607	607	607	618	618	618	618	618	618	7,353
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,065	3,065	3,065	3,065	3,065	3,065	3,094	3,094	3,094	3,094	3,094	3,067	36,931
	a Recoverable Costs Allocated to Energy		236	236	236	236	236	236	238	238	238	238	238	236	2,841
	b Recoverable Costs Allocated to Demand		2,830	2,830	2,830	2,830	2,830	2,830	2,856	2,856	2,856	2,856	2,856	2,831	34,090
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		230	230	230	230	230	230	232	232	232	232	231	229	2,769
13	Retail Demand-Related Recoverable Costs (I)		2,750	2,750	2,750	2,750	2,750	2,750	2,776	2,776	2,776	2,776	2,776	2,751	33,130
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,979	2,980	2,980	2,980	2,980	2,980	3,008	3,008	3,008	3,008	3,007	2,981	35,898

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Dechlorination System

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	
3	Less: Accumulated Depreciation (C)	(243,768)	(245,024)	(246,281)	(247,537)	(248,793)	(250,049)	(251,306)	(252,562)	(253,818)	(255,075)	(256,331)	(257,600)	(258,869)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	136,929	135,673	134,416	133,160	131,904	130,648	129,391	128,135	126,879	125,622	124,366	123,097	121,828	
6	Average Net Investment		136,301	135,045	133,788	132,532	131,276	130,019	128,763	127,507	126,251	124,994	123,732	122,463	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		630	624	618	612	607	601	599	594	588	582	576	564	7,194
	b Debt Component (Line 6 x Debt Component x 1/12)		156	154	153	151	150	148	150	148	147	145	144	142	1,788
8	Investment Expenses														
	a Depreciation (E)		1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,269	1,269	15,101
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,042	2,035	2,027	2,020	2,013	2,006	2,005	1,998	1,991	1,983	1,989	1,975	24,083
	a Recoverable Costs Allocated to Energy		157	157	156	155	155	154	154	154	153	153	153	152	1,853
	b Recoverable Costs Allocated to Demand		1,885	1,878	1,871	1,865	1,858	1,851	1,851	1,844	1,838	1,831	1,836	1,823	22,231
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		153	153	152	152	151	151	150	150	149	149	149	148	1,805
13	Retail Demand-Related Recoverable Costs (I)		1,832	1,825	1,819	1,812	1,806	1,799	1,799	1,792	1,786	1,779	1,784	1,772	21,605
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,985	1,978	1,971	1,964	1,957	1,950	1,949	1,942	1,935	1,928	1,933	1,919	23,410

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	20,968	20,968	20,968	20,968	20,968	20,968	20,968	
3	Less: Accumulated Depreciation (C)	(50,860)	(51,088)	(51,315)	(51,542)	(51,770)	(51,997)	(52,146)	(52,215)	(52,284)	(52,353)	(52,422)	(52,492)	(52,562)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	18,063	17,835	17,608	17,381	17,153	16,926	(31,178)	(31,247)	(31,316)	(31,386)	(31,455)	(31,525)	(31,595)	
6	Average Net Investment		17,949	17,722	17,494	17,267	17,039	(7,126)	(31,213)	(31,282)	(31,351)	(31,420)	(31,490)	(31,560)	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		83	82	81	80	79	(33)	(145)	(146)	(146)	(146)	(147)	(145)	(504)
	b Debt Component (Line 6 x Debt Component x 1/12)		20	20	20	20	19	(8)	(36)	(36)	(36)	(37)	(37)	(37)	(127)
8	Investment Expenses														
	a Depreciation (E)		227	227	227	227	227	148	69	69	69	69	70	70	1,702
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		331	330	328	327	326	107	(112)	(113)	(113)	(114)	(113)	(112)	1,071
	a Recoverable Costs Allocated to Energy		25	25	25	25	25	8	(9)	(9)	(9)	(9)	(9)	(9)	82
	b Recoverable Costs Allocated to Demand		305	304	303	302	301	99	(104)	(104)	(104)	(105)	(105)	(103)	989
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		25	25	25	25	24	8	(8)	(8)	(8)	(9)	(8)	(8)	80
13	Retail Demand-Related Recoverable Costs (I)		297	296	294	293	292	96	(101)	(101)	(102)	(102)	(102)	(101)	961
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		322	320	319	318	317	104	(109)	(110)	(110)	(110)	(110)	(109)	1,041

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $47,955 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unloading Secondary Containment

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(84,109)	(84,443)	(84,778)	(85,113)	(85,448)	(85,783)	(86,118)	(86,453)	(86,788)	(87,123)	(87,458)	(87,796)	(88,134)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	17,387	17,052	16,717	16,382	16,047	15,712	15,377	15,042	14,707	14,372	14,037	13,699	13,361	
6	Average Net Investment		17,219	16,884	16,549	16,214	15,879	15,544	15,209	14,875	14,540	14,205	13,868	13,530	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		80	78	76	75	73	72	71	69	68	66	65	62	855
	b Debt Component (Line 6 x Debt Component x 1/12)		20	19	19	19	18	18	18	17	17	17	16	16	212
8	Investment Expenses														
	a Depreciation (E)		335	335	335	335	335	335	335	335	335	335	338	338	4,026
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		434	432	430	428	426	425	423	421	420	418	419	416	5,093
	a Recoverable Costs Allocated to Energy		33	33	33	33	33	33	33	32	32	32	32	32	392
	b Recoverable Costs Allocated to Demand		401	399	397	395	394	392	391	389	387	385	387	384	4,702
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		33	32	32	32	32	32	32	32	31	31	31	31	382
13	Retail Demand-Related Recoverable Costs (I)		389	388	386	384	383	381	380	378	376	375	376	373	4,569
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		422	420	418	416	415	413	412	410	408	406	407	405	4,951

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(49,661)	(49,858)	(50,054)	(50,251)	(50,447)	(50,644)	(50,840)	(51,037)	(51,233)	(51,430)	(51,626)	(51,825)	(52,023)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	9,882	9,685	9,489	9,292	9,096	8,899	8,703	8,506	8,310	8,113	7,917	7,718	7,520	
6	Average Net Investment		9,783	9,587	9,390	9,194	8,997	8,801	8,604	8,408	8,211	8,015	7,817	7,619	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		45	44	43	42	42	41	40	39	38	37	36	35	484
	b Debt Component (Line 6 x Debt Component x 1/12)		11	11	11	10	10	10	10	10	10	9	9	9	120
8	Investment Expenses														
	a Depreciation (E)		196	196	196	196	196	196	196	196	196	196	198	198	2,362
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		253	252	251	249	248	247	247	245	244	243	244	242	2,966
	a Recoverable Costs Allocated to Energy		19	19	19	19	19	19	19	19	19	19	19	19	228
	b Recoverable Costs Allocated to Demand		233	232	231	230	229	228	228	227	225	224	225	224	2,738
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		19	19	19	19	19	19	18	18	18	18	18	18	222
13	Retail Demand-Related Recoverable Costs (I)		227	226	225	224	223	222	221	220	219	218	219	217	2,661
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		246	245	244	243	241	240	240	239	237	236	237	236	2,883

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	
3	Less: Accumulated Depreciation (C)	(129,581)	(130,520)	(131,459)	(132,398)	(133,338)	(134,277)	(135,216)	(136,155)	(137,095)	(138,034)	(138,973)	(139,922)	(140,871)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	155,041	154,102	153,163	152,223	151,284	150,345	149,406	148,466	147,527	146,588	145,649	144,700	143,751	
6	Average Net Investment		154,572	153,632	152,693	151,754	150,815	149,875	148,936	147,997	147,058	146,118	145,174	144,226	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		714	710	706	701	697	693	693	689	685	680	676	664	8,307
	b Debt Component (Line 6 x Debt Component x 1/12)		177	175	174	173	172	171	173	172	171	170	169	168	2,065
8	Investment Expenses														
	a Depreciation (E)		939	939	939	939	939	939	939	939	939	939	949	949	11,290
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,830	1,825	1,819	1,814	1,808	1,803	1,806	1,800	1,795	1,789	1,793	1,780	21,662
	a Recoverable Costs Allocated to Energy		141	140	140	140	139	139	139	138	138	138	138	137	1,666
	b Recoverable Costs Allocated to Demand		1,689	1,684	1,679	1,674	1,669	1,664	1,667	1,662	1,657	1,652	1,655	1,643	19,996
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		137	137	136	136	136	136	135	135	135	134	134	133	1,624
13	Retail Demand-Related Recoverable Costs (I)		1,642	1,637	1,632	1,627	1,622	1,617	1,620	1,615	1,610	1,605	1,609	1,597	19,433
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,779	1,774	1,768	1,763	1,758	1,753	1,755	1,750	1,745	1,739	1,743	1,730	21,057

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	
3	Less: Accumulated Depreciation (C)	(2,057,330)	(2,068,111)	(2,078,892)	(2,089,673)	(2,100,454)	(2,111,236)	(2,122,017)	(2,132,798)	(2,143,579)	(2,154,360)	(2,165,141)	(2,175,968)	(2,186,795)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	707,049	696,267	685,486	674,705	663,924	653,143	642,362	631,581	620,800	610,019	599,238	588,411	577,583	
6	Average Net Investment		701,658	690,877	680,096	669,315	658,534	647,753	636,972	626,190	615,409	604,628	593,824	582,997	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,242	3,193	3,143	3,093	3,043	2,993	2,965	2,915	2,865	2,815	2,764	2,684	35,715
	b Debt Component (Line 6 x Debt Component x 1/12)		801	789	777	764	752	740	740	728	715	703	690	677	8,876
8	Investment Expenses														
	a Depreciation (E)		10,781	10,781	10,781	10,781	10,781	10,781	10,781	10,781	10,781	10,781	10,827	10,827	129,465
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		14,825	14,763	14,700	14,638	14,576	14,514	14,486	14,424	14,361	14,298	14,281	14,189	174,056
	a Recoverable Costs Allocated to Energy		1,140	1,136	1,131	1,126	1,121	1,116	1,114	1,110	1,105	1,100	1,099	1,091	13,389
	b Recoverable Costs Allocated to Demand		13,684	13,627	13,570	13,512	13,455	13,398	13,372	13,314	13,256	13,198	13,183	13,097	160,667
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		1,110	1,107	1,102	1,098	1,093	1,091	1,087	1,082	1,077	1,072	1,068	1,061	13,048
13	Retail Demand-Related Recoverable Costs (I)		13,299	13,243	13,187	13,132	13,076	13,020	12,995	12,939	12,883	12,827	12,811	12,728	156,140
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		14,409	14,350	14,290	14,230	14,169	14,111	14,082	14,021	13,960	13,898	13,880	13,789	169,188

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	145,493	281	0	0	0	0	(22,690)	0	744	0	0	123,828
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	72,746	141	0	0	0	0	(6,673)	0	219	30,048	0	96,480
2	Plant-in-Service/Depreciation Base (B)	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	
3	Less: Accumulated Depreciation (C)	39,908	39,210	111,258	110,701	110,003	109,305	108,607	107,909	100,538	99,840	99,360	128,708	128,007	
4	CWIP - Non Interest Bearing	340,829	340,829	486,322	486,603	486,603	486,603	486,603	486,603	463,914	463,914	464,658	464,658	464,658	
5	Net Investment (Lines 2 + 3 + 4) (A)	559,699	559,001	776,542	776,266	775,568	774,870	774,172	773,474	743,413	742,715	742,980	772,327	771,626	
6	Average Net Investment		559,350	667,771	776,404	775,917	775,219	774,521	773,823	758,444	743,064	742,848	757,654	771,977	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,585	3,086	3,588	3,586	3,582	3,579	3,602	3,531	3,459	3,458	3,527	3,554	41,136
	b Debt Component (Line 6 x Debt Component x 1/12)		639	763	887	886	885	885	899	881	863	863	880	897	10,228
8	Investment Expenses														
	a Depreciation (E)		698	698	698	698	698	698	698	698	698	698	701	701	8,381
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,921	4,546	5,172	5,170	5,166	5,162	5,199	5,110	5,020	5,019	5,108	5,152	59,746
	a Recoverable Costs Allocated to Energy		302	350	398	398	397	397	400	393	386	386	393	396	4,596
	b Recoverable Costs Allocated to Demand		3,620	4,197	4,774	4,772	4,768	4,764	4,799	4,717	4,634	4,633	4,715	4,756	55,150
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		294	341	388	388	387	388	390	383	377	376	382	385	4,479
13	Retail Demand-Related Recoverable Costs (I)		3,518	4,078	4,640	4,637	4,634	4,630	4,664	4,584	4,504	4,502	4,582	4,622	53,596
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,811	4,419	5,028	5,025	5,021	5,018	5,054	4,967	4,880	4,879	4,964	5,007	58,075

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	
3	Less: Accumulated Depreciation (C)	(6,384,689)	(6,422,064)	(6,459,439)	(6,496,815)	(6,534,190)	(6,571,565)	(6,608,927)	(6,646,276)	(6,683,625)	(6,720,974)	(6,758,323)	(6,795,672)	(6,833,021)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	8,565,435	8,528,060	8,490,685	8,453,309	8,415,934	8,378,559	8,330,634	8,293,285	8,255,936	8,218,587	8,181,238	8,143,889	8,106,540	
6	Average Net Investment		8,546,748	8,509,372	8,471,997	8,434,622	8,397,246	8,354,596	8,311,959	8,274,610	8,237,261	8,199,913	8,162,564	8,125,215	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		39,495	39,322	39,149	38,976	38,804	38,607	38,692	38,518	38,344	38,171	37,997	37,408	463,483
	b Debt Component (Line 6 x Debt Component x 1/12)		9,760	9,718	9,675	9,632	9,590	9,541	9,658	9,615	9,572	9,528	9,485	9,441	115,216
8	Investment Expenses														
	a Depreciation (E)		37,375	37,375	37,375	37,375	37,375	37,362	37,349	37,349	37,349	37,349	37,349	37,349	448,332
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		21,889	21,889	21,889	21,889	21,889	21,889	21,889	21,889	21,889	21,889	21,889	21,889	262,665
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		108,519	108,304	108,088	107,873	107,657	107,398	107,588	107,371	107,154	106,937	106,719	106,088	1,289,696
	a Recoverable Costs Allocated to Energy		8,348	8,331	8,314	8,298	8,281	8,261	8,276	8,259	8,243	8,226	8,209	8,161	99,207
	b Recoverable Costs Allocated to Demand		100,171	99,973	99,774	99,575	99,376	99,137	99,312	99,112	98,911	98,711	98,510	97,927	1,190,488
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		8,125	8,119	8,104	8,094	8,072	8,073	8,073	8,053	8,038	8,017	7,982	7,932	96,681
13	Retail Demand-Related Recoverable Costs (I)		97,349	97,156	96,963	96,770	96,576	96,344	96,514	96,320	96,125	95,930	95,735	95,168	1,156,950
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		105,474	105,275	105,067	104,863	104,648	104,417	104,587	104,373	104,163	103,947	103,717	103,100	1,253,631

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $10,562.91 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		42,030	247,607	383,462	(66,581)	(30,308)	11,621	19,852	(26,283)	1,776	10,622	1,165	15,640	610,604
	b Clearings to Plant		0	122,776	2,357,835	61,304	(32,908)	18,163	4,025	(37,404)	103	10,622	1,165	0	2,505,681
	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	1,061	1,061
2	Plant-in-Service/Depreciation Base (B)	18,512,562	18,512,562	18,635,339	20,993,174	21,054,478	21,021,569	21,039,732	21,043,758	21,006,353	21,006,456	21,017,078	21,018,243	21,018,243	
3	Less: Accumulated Depreciation (C)	(1,514,451)	(1,586,650)	(1,659,088)	(1,736,364)	(1,818,357)	(1,900,405)	(1,982,425)	(2,064,487)	(2,146,485)	(2,228,410)	(2,310,356)	(2,392,675)	(2,473,936)	
4	CWIP - Non Interest Bearing	2,469,687	2,511,717	2,636,548	662,175	534,290	536,891	530,348	546,175	557,296	558,970	558,970	558,970	574,610	
5	Net Investment (Lines 2 + 3 + 4) (A)	19,467,799	19,437,629	19,612,798	19,918,984	19,770,410	19,658,055	19,587,656	19,525,445	19,417,164	19,337,016	19,265,692	19,184,538	19,118,917	
6	Average Net Investment		19,452,714	19,525,214	19,765,891	19,844,697	19,714,232	19,622,855	19,556,550	19,471,305	19,377,090	19,301,354	19,225,115	19,151,728	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		89,891	90,226	91,338	91,702	91,099	90,677	91,036	90,639	90,200	89,848	89,493	88,175	1,084,324
	b Debt Component (Line 6 x Debt Component x 1/12)		22,215	22,298	22,573	22,663	22,514	22,409	22,725	22,626	22,516	22,428	22,340	22,254	269,560
8	Investment Expenses														
	a Depreciation (E)		72,199	72,438	77,276	81,993	82,048	82,020	82,063	81,998	81,925	81,946	82,319	82,321	960,546
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		184,305	184,962	191,186	196,358	195,661	195,106	195,823	195,262	194,642	194,222	194,152	192,750	2,314,430
	a Recoverable Costs Allocated to Energy		14,177	14,228	14,707	15,104	15,051	15,008	15,063	15,020	14,972	14,940	14,935	14,827	178,033
	b Recoverable Costs Allocated to Demand		170,128	170,734	176,480	181,253	180,611	180,098	180,760	180,242	179,669	179,282	179,217	177,923	2,136,397
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		13,799	13,866	14,335	14,732	14,670	14,666	14,694	14,645	14,601	14,560	14,521	14,411	173,501
13	Retail Demand-Related Recoverable Costs (I)		165,335	165,924	171,508	176,147	175,522	175,024	175,668	175,164	174,607	174,231	174,168	172,911	2,076,210
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		179,133	179,790	185,842	190,880	190,192	189,690	190,361	189,809	189,208	188,791	188,689	187,322	2,249,710

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 4397 fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	169,319	122,467	(119,837)	0	197,006	0	0	5,578	2,806	192,055	(85,032)	484,362
	b Clearings to Plant		0	0	159	41,397	0	0	0	0	0	0	0	0	41,556
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	34,145	48,055	(3,359)	0	118,204	0	0	3,347	0	115,233	(51,019)	264,605
2	Plant-in-Service/Depreciation Base (B)	120,470,679	120,470,679	120,470,679	120,470,837	120,512,234	120,512,234	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	
3	Less: Accumulated Depreciation (C)	(33,871,915)	(34,276,736)	(34,647,413)	(35,004,180)	(35,412,430)	(35,817,389)	(36,102,530)	(36,504,261)	(36,905,992)	(37,304,377)	(37,706,108)	(37,996,565)	(38,453,274)	
4	CWIP - Non Interest Bearing	1,007	1,007	170,326	292,634	131,401	131,401	328,407	328,407	328,407	333,985	336,791	528,845	443,813	
5	Net Investment (Lines 2 + 3 + 4) (A)	86,599,771	86,194,949	85,993,592	85,759,292	85,231,205	84,826,246	83,809,796	83,408,065	83,006,334	82,613,527	82,214,601	82,116,199	81,574,458	
6	Average Net Investment		86,397,360	86,094,271	85,876,442	85,495,248	85,028,726	84,318,021	83,608,931	83,207,199	82,809,930	82,414,064	82,165,400	81,845,329	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		399,242	397,842	396,835	395,074	392,918	389,634	389,200	387,330	385,480	383,637	382,480	376,816	4,676,486
	b Debt Component (Line 6 x Debt Component x 1/12)		98,666	98,320	98,071	97,636	97,103	96,291	97,154	96,687	96,225	95,765	95,476	95,104	1,162,497
8	Investment Expenses														
	a Depreciation (E)		394,766	394,766	394,766	394,835	394,903	393,403	391,902	391,902	391,902	391,902	395,861	395,861	4,726,769
	b Amortization (F)		10,056	10,056	10,056	10,056	10,056	9,942	9,829	9,829	9,829	9,829	9,829	9,829	119,195
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		902,730	900,983	899,728	897,600	894,979	889,270	888,084	885,747	883,437	881,134	883,646	877,610	10,684,947
	a Recoverable Costs Allocated to Energy		69,441	69,306	69,210	69,046	68,845	68,405	68,314	68,134	67,957	67,780	67,973	67,508	821,919
	b Recoverable Costs Allocated to Demand		833,289	831,677	830,518	828,554	826,135	820,864	819,770	817,613	815,480	813,354	815,673	810,102	9,863,028
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		67,586	67,544	67,459	67,346	67,102	66,845	66,639	66,433	66,270	66,057	66,092	65,616	800,989
13	Retail Demand-Related Recoverable Costs (I)		809,813	808,246	807,120	805,211	802,861	797,739	796,675	794,579	792,506	790,440	792,694	787,279	9,585,164
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		877,399	875,790	874,579	872,557	869,963	864,584	863,314	861,012	858,776	856,497	858,786	852,895	10,386,153

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $928,315 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Portions of PEs 1158, 1167 and 1199 have a 7-year amortization period. PE 1287 is fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	
3	Less: Accumulated Depreciation (C)	(391,513)	(394,763)	(398,014)	(401,264)	(404,515)	(407,766)	(411,016)	(414,267)	(417,518)	(420,768)	(424,019)	(427,300)	(430,582)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	556,412	553,162	549,911	546,660	543,410	540,159	536,909	533,658	530,407	527,157	523,906	520,624	517,343	
6	Average Net Investment		554,787	551,536	548,286	545,035	541,784	538,534	535,283	532,033	528,782	525,531	522,265	518,984	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,564	2,549	2,534	2,519	2,504	2,489	2,492	2,477	2,461	2,446	2,431	2,389	29,853
	b Debt Component (Line 6 x Debt Component x 1/12)		634	630	626	622	619	615	622	618	614	611	607	603	7,421
8	Investment Expenses														
	a Depreciation (E)		3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,124	3,124	37,184
	b Amortization (F)		157	157	157	157	157	157	157	157	157	157	157	157	1,885
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		6,448	6,429	6,410	6,392	6,373	6,354	6,364	6,345	6,327	6,308	6,320	6,274	76,344
	a Recoverable Costs Allocated to Energy		496	495	493	492	490	489	490	488	487	485	486	483	5,873
	b Recoverable Costs Allocated to Demand		5,952	5,935	5,917	5,900	5,883	5,865	5,875	5,857	5,840	5,822	5,833	5,791	70,471
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		483	482	481	480	478	478	478	476	475	473	473	469	5,723
13	Retail Demand-Related Recoverable Costs (I)		5,784	5,767	5,751	5,734	5,717	5,700	5,709	5,692	5,675	5,658	5,669	5,628	68,486
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,267	6,249	6,231	6,213	6,195	6,178	6,187	6,168	6,150	6,131	6,142	6,097	74,209

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist $919,836; Smith $14,895.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 4418 has a 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	(32,014)	(32,222)	(32,429)	(32,637)	(32,844)	(33,052)	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	30,856	30,648	30,441	30,234	30,026	29,819	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	
6	Average Net Investment		30,752	30,545	30,337	30,130	29,922	(1,668)	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		142	141	140	139	138	(8)	(154)	(154)	(154)	(154)	(154)	(153)	(231)
	b Debt Component (Line 6 x Debt Component x 1/12)		35	35	35	34	34	(2)	(39)	(39)	(39)	(39)	(39)	(39)	(60)
8	Investment Expenses														
	a Depreciation (E)		207	207	207	207	207	104	0	0	0	0	0	0	1,141
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		385	384	382	381	380	94	(193)	(193)	(193)	(193)	(193)	(191)	850
	a Recoverable Costs Allocated to Energy		30	30	29	29	29	7	(15)	(15)	(15)	(15)	(15)	(15)	65
	b Recoverable Costs Allocated to Demand		355	354	353	352	351	87	(178)	(178)	(178)	(178)	(178)	(176)	785
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		29	29	29	29	28	7	(14)	(14)	(14)	(14)	(14)	(14)	64
13	Retail Demand-Related Recoverable Costs (I)		345	344	343	342	341	84	(173)	(173)	(173)	(173)	(173)	(171)	763
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		374	373	372	370	369	92	(187)	(187)	(187)	(187)	(187)	(186)	826

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $62,870 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	
3	Less: Accumulated Depreciation (C)	(5,269,811)	(5,316,003)	(5,362,196)	(5,408,388)	(5,454,581)	(5,500,773)	(5,546,797)	(5,592,653)	(5,638,508)	(5,684,364)	(5,730,220)	(5,776,538)	(5,822,857)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	8,727,885	8,681,692	8,635,500	8,589,308	8,543,115	8,496,923	8,348,842	8,302,986	8,257,130	8,211,275	8,165,419	8,119,100	8,072,782	
6	Average Net Investment		8,704,789	8,658,596	8,612,404	8,566,211	8,520,019	8,422,882	8,325,914	8,280,058	8,234,203	8,188,347	8,142,260	8,095,941	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,225	40,011	39,798	39,584	39,371	38,922	38,757	38,544	38,330	38,117	37,902	37,274	466,835
	b Debt Component (Line 6 x Debt Component x 1/12)		9,941	9,888	9,835	9,783	9,730	9,619	9,675	9,621	9,568	9,515	9,461	9,407	116,044
8	Investment Expenses														
	a Depreciation (E)		46,192	46,192	46,192	46,192	46,192	46,024	45,856	45,856	45,856	45,856	46,319	46,319	553,046
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		96,358	96,092	95,826	95,559	95,293	94,565	94,287	94,021	93,754	93,487	93,682	93,000	1,135,925
	a Recoverable Costs Allocated to Energy		7,412	7,392	7,371	7,351	7,330	7,274	7,253	7,232	7,212	7,191	7,206	7,154	87,379
	b Recoverable Costs Allocated to Demand		88,946	88,700	88,454	88,209	87,963	87,291	87,035	86,788	86,542	86,296	86,476	85,846	1,048,546
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		7,214	7,204	7,185	7,170	7,145	7,108	7,075	7,052	7,033	7,009	7,007	6,953	85,154
13	Retail Demand-Related Recoverable Costs (I)		86,440	86,201	85,963	85,724	85,485	84,832	84,583	84,343	84,104	83,865	84,040	83,428	1,019,006
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		93,654	93,405	93,147	92,893	92,630	91,940	91,658	91,395	91,137	90,873	91,047	90,381	1,104,160

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $102,057 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	35,775	99,713	19,086	105	0	0	0	0	0	0	0	154,678
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	45,745	(20,447)	63	0	0	0	0	3	0	0	25,363
2	Plant-in-Service/Depreciation Base (B)	19,846,127	19,846,127	19,846,127	19,846,127	19,846,127	19,846,127	19,748,717	19,748,717	19,748,717	19,748,717	19,748,717	19,748,717	19,748,717	
3	Less: Accumulated Depreciation (C)	(5,653,498)	(5,718,990)	(5,784,482)	(5,804,230)	(5,890,169)	(5,955,598)	(6,020,930)	(6,086,101)	(6,151,271)	(6,216,442)	(6,281,610)	(6,347,439)	(6,413,268)	
4	CWIP - Non Interest Bearing	378,586	378,586	414,360	514,073	533,159	533,264	533,264	533,264	533,264	533,264	533,264	533,264	533,264	
5	Net Investment (Lines 2 + 3 + 4) (A)	14,571,215	14,505,722	14,476,005	14,555,970	14,489,117	14,423,793	14,261,051	14,195,880	14,130,710	14,065,539	14,000,371	13,934,542	13,868,713	
6	Average Net Investment		14,538,469	14,490,864	14,515,987	14,522,543	14,456,455	14,342,422	14,228,466	14,163,295	14,098,124	14,032,955	13,967,456	13,901,627	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		67,182	66,962	67,078	67,109	66,803	66,276	66,234	65,930	65,627	65,323	65,019	64,003	793,547
	b Debt Component (Line 6 x Debt Component x 1/12)		16,603	16,549	16,577	16,585	16,509	16,379	16,533	16,458	16,382	16,306	16,230	16,154	197,265
8	Investment Expenses														
	a Depreciation (E)		65,492	65,492	65,492	65,492	65,492	65,331	65,171	65,171	65,171	65,171	65,829	65,829	785,134
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		149,277	149,003	149,148	149,186	148,805	147,987	147,938	147,559	147,180	146,800	147,078	145,986	1,775,946
	a Recoverable Costs Allocated to Energy		11,483	11,462	11,473	11,476	11,447	11,384	11,380	11,351	11,322	11,292	11,314	11,230	136,611
	b Recoverable Costs Allocated to Demand		137,795	137,541	137,675	137,710	137,358	136,603	136,558	136,208	135,858	135,508	135,764	134,756	1,639,334
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		11,176	11,170	11,183	11,193	11,157	11,124	11,101	11,067	11,041	11,005	11,001	10,915	133,133
13	Retail Demand-Related Recoverable Costs (I)		133,913	133,666	133,796	133,830	133,489	132,755	132,711	132,371	132,031	131,691	131,939	130,960	1,593,151
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		145,089	144,837	144,979	145,023	144,645	143,879	143,811	143,438	143,071	142,696	142,940	141,875	1,726,283

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $97,420 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		677,075	457,510	340,738	1,109,148	(202,826)	(6,713)	0	693	0	0	0	1,056	2,376,681
	b Clearings to Plant		0	0	0	0	0	0	0	3,798,266	0	0	0	0	3,798,266
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	6,153,140	6,153,140	6,153,140	6,153,140	6,153,140	6,153,140	6,153,140	6,153,140	9,951,406	9,951,406	9,951,406	9,951,406	9,951,406	
3	Less: Accumulated Depreciation (C)	(2,643,033)	(2,663,339)	(2,683,644)	(2,703,950)	(2,724,255)	(2,744,560)	(2,764,866)	(2,785,171)	(2,812,883)	(2,848,002)	(2,883,120)	(2,918,507)	(2,953,894)	
4	CWIP - Non Interest Bearing	1,422,641	2,099,716	2,557,226	2,897,964	4,007,111	3,804,286	3,797,573	3,797,573.39	0	0	0	0	1,056	
5	Net Investment (Lines 2 + 3 + 4) (A)	4,932,748	5,589,518	6,026,722	6,347,154	7,435,997	7,212,866	7,185,848	7,165,543	7,138,523	7,103,405	7,068,286	7,032,899	6,998,568	
6	Average Net Investment		5,261,133	5,808,120	6,186,938	6,891,575	7,324,431	7,199,357	7,175,695	7,152,033	7,120,964	7,085,845	7,050,593	7,015,733	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		24,312	26,839	28,590	31,846	33,846	33,268	33,403	33,293	33,148	32,985	32,821	32,300	376,650
	b Debt Component (Line 6 x Debt Component x 1/12)		6,008	6,633	7,065	7,870	8,365	8,222	8,338	8,311	8,275	8,234	8,193	8,152	93,665
8	Investment Expenses														
	a Depreciation (E)		20,305	20,305	20,305	20,305	20,305	20,305	20,305	27,712	35,119	35,119	35,387	35,387	310,861
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		50,625	53,778	55,961	60,022	62,516	61,795	62,046	69,315	76,541	76,337	76,400	75,840	781,176
	a Recoverable Costs Allocated to Energy		3,894	4,137	4,305	4,617	4,809	4,753	4,773	5,332	5,888	5,872	5,877	5,834	60,090
	b Recoverable Costs Allocated to Demand		46,731	49,641	51,656	55,404	57,707	57,042	57,274	63,983	70,653	70,465	70,523	70,006	721,086
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		3,790	4,032	4,196	4,503	4,687	4,645	4,656	5,199	5,742	5,723	5,714	5,670	58,557
13	Retail Demand-Related Recoverable Costs (I)		45,414	48,242	50,201	53,844	56,081	55,435	55,660	62,181	68,663	68,480	68,537	68,034	700,771
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		49,205	52,274	54,396	58,347	60,769	60,080	60,316	67,380	74,405	74,203	74,251	73,704	759,328

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Compliance Program

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		30,461	77,972	1,117,284	60,670	(262,147)	18,953	788,484	549,026	617,367	658,877	211,107	1,345,878	5,213,931
	b Clearings to Plant		(1,600)	22,198	20,090	4,644,661	(21,569)	392,464	24,241	32,359	87,946	63,048	14,251	2,724,886	8,002,975
	c Retirements		0	0	47,724	105,244	0	0	0	0	85,265	207,732	7,892	2,567,029	3,020,886
	d Other		0	13,810	19,737	18,935	(1,639)	28,041	42,337	16,408	(78,904)	496,143	(91,761)	260,330	723,437
2	Plant-in-Service/Depreciation Base (B)	1,340,517,152	1,340,515,552	1,340,537,750	1,340,510,116	1,345,049,533	1,345,027,964	1,343,188,491	1,343,212,732	1,343,245,091	1,343,247,772	1,343,130,274	1,343,136,634	1,343,294,490	
3	Less: Accumulated Depreciation (C)	(273,951,952)	(277,818,634)	(281,671,537)	(285,470,767)	(289,220,722)	(293,104,218)	(296,956,449)	(300,780,090)	(304,629,747)	(308,489,518)	(311,651,646)	(315,633,559)	(316,705,226)	
4	CWIP - Non Interest Bearing	4,804,422	4,836,483	4,892,257	5,989,451	1,405,459	1,164,882	791,371	1,555,614	2,072,280	2,601,701	3,197,530	3,394,385	2,015,378	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,071,369,622	1,067,533,401	1,063,758,470	1,061,028,800	1,057,234,271	1,053,088,628	1,047,023,413	1,043,988,255	1,040,687,625	1,037,359,956	1,034,676,158	1,030,897,460	1,028,604,642	
6	Average Net Investment		1,069,451,511	1,065,645,935	1,062,393,635	1,059,131,536	1,055,161,450	1,050,056,021	1,045,505,834	1,042,337,940	1,039,023,790	1,036,018,057	1,032,786,809	1,029,751,051	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,941,935	4,924,350	4,909,321	4,894,247	4,875,901	4,852,309	4,866,830	4,852,083	4,836,656	4,822,664	4,807,623	4,740,974	58,324,892
	b Debt Component (Line 6 x Debt Component x 1/12)		1,221,314	1,216,968	1,213,254	1,209,528	1,204,994	1,199,164	1,214,878	1,211,197	1,207,346	1,203,853	1,200,098	1,196,571	14,499,163
8	Investment Expenses														
	a Depreciation (E)		3,838,491	3,838,522	3,838,500	3,845,943	3,853,420	3,851,836	3,850,308	3,850,394	3,850,462	3,850,333	3,882,374	3,883,356	46,233,939
	b Amortization (F)		28,191	28,191	28,191	28,191	28,437	28,437	15,670	15,670	15,670	15,670	15,670	15,670	263,657
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		562,653	562,653	562,653	562,653	562,653	562,653	562,653	562,653	562,653	562,653	562,653	562,653	6,751,836
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,592,584	10,570,683	10,551,918	10,540,562	10,525,406	10,494,398	10,510,339	10,491,996	10,472,787	10,455,173	10,468,417	10,399,224	126,073,487
	a Recoverable Costs Allocated to Energy		814,814	813,129	811,686	810,812	809,647	807,261	808,488	807,077	805,599	804,244	805,263	799,940	9,697,961
	b Recoverable Costs Allocated to Demand		9,777,770	9,757,553	9,740,232	9,729,749	9,715,759	9,687,137	9,701,851	9,684,920	9,667,188	9,650,929	9,663,154	9,599,284	116,375,527
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		793,052	792,453	791,148	790,846	789,156	788,850	788,657	786,928	785,608	783,803	782,979	777,518	9,450,997
13	Retail Demand-Related Recoverable Costs (I)		9,502,308	9,482,661	9,465,828	9,455,640	9,442,044	9,414,228	9,428,528	9,412,073	9,394,841	9,379,040	9,390,921	9,328,850	113,096,960
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,295,359	10,275,114	10,256,975	10,246,486	10,231,200	10,203,078	10,217,185	10,199,001	10,180,449	10,162,843	10,173,900	10,106,367	122,547,957

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $2,231,937 due to synchronization with the NEE accounting system at the retirement unit level.
(B) Beginning Balances: Crist $783,784,344; Smith $229,742; Daniel $373,548,987, Scherer $182,954,079. Ending Balances: Crist $785,945,326; Smith $229,742; Daniel $374,180,865, Scherer $182,938,558.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1168 and portions of PEs 1222, 1233, 1279, 1728, 1909 and 1950 have a 7 year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	33,250	(33,250)	16,735	0	12	278,262	118,190	413,200
	b Clearings to Plant		0	0	0	0	0	33,250	(33,250)	16,735	0	0	0	0	16,735
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	835,726	835,726	835,726	835,726	835,726	835,726	868,976	835,726	852,461	852,461	852,461	852,461	852,461	
3	Less: Accumulated Depreciation (C)	(16,524)	(19,282)	(22,040)	(24,798)	(27,556)	(30,314)	(33,126)	(35,939)	(38,725)	(41,538)	(44,351)	(47,192)	(50,034)	
4	CWIP - Non Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	0	12	278,274	396,465	
5	Net Investment (Lines 2 + 3 + 4) (A)	819,202	816,444	813,686	810,928	808,170	805,412	835,849	799,787	813,736	810,923	808,122	1,083,543	1,198,891	
6	Average Net Investment		817,823	815,065	812,307	809,549	806,791	820,631	817,818	806,761	812,330	809,523	945,832	1,141,217	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,779	3,766	3,754	3,741	3,728	3,792	3,807	3,755	3,781	3,768	4,403	5,254	47,330
	b Debt Component (Line 6 x Debt Component x 1/12)		934	931	928	925	921	937	950	937	944	941	1,099	1,326	11,773
8	Investment Expenses														
	a Depreciation (E)		2,758	2,758	2,758	2,758	2,758	2,813	2,813	2,786	2,813	2,813	2,842	2,842	33,510
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,471	7,455	7,439	7,423	7,407	7,542	7,570	7,478	7,538	7,522	8,343	9,422	92,612
	a Recoverable Costs Allocated to Energy		575	573	572	571	570	580	582	575	580	579	642	725	7,124
	b Recoverable Costs Allocated to Demand		6,896	6,882	6,867	6,852	6,838	6,962	6,988	6,903	6,959	6,943	7,702	8,697	85,488
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		559	559	558	557	555	567	568	561	565	564	624	704	6,942
13	Retail Demand-Related Recoverable Costs (I)		6,702	6,688	6,674	6,659	6,645	6,766	6,791	6,709	6,763	6,748	7,485	8,452	83,080
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,261	7,247	7,231	7,216	7,200	7,333	7,359	7,270	7,328	7,312	8,109	9,156	90,022

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) PE 1280 is fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		4,101,606	3,125,600	13,834,252	(1,080,825)	2,657,799	4,065,374	4,696,012	2,844,165	(4,507,528)	7,030,124	3,482,115	3,292,847	43,541,542
	b Clearings to Plant		0	0	482,727	1,156,841	11,454,851	821,337	511,358	592,159	167,701	32,658	50,306	1,709,464	16,979,403
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	262,985	190,794	1,054,916	963,914	0	0	0	0	525,507	249,129	75,403	3,322,649
2	Plant-in-Service/Depreciation Base (B)	3,298,422	3,298,422	3,298,422	3,781,148	4,937,990	16,392,841	17,214,178	17,725,536	18,317,695	17,812,214	17,844,873	17,895,179	19,585,347	
3	Less: Accumulated Depreciation (C)	(37,015,158)	(37,076,239)	(36,874,335)	(36,745,563)	(35,755,867)	(34,869,750)	(34,958,606)	(35,048,914)	(35,140,969)	(35,209,664)	(34,776,438)	(34,620,186)	(34,638,588)	
4	CWIP - Non Interest Bearing	46,403,562	50,505,168	53,630,768	66,982,293	64,744,627	55,947,575	59,191,611	63,376,266	65,628,272	60,953,043	67,950,509	71,382,318	72,965,701	
5	Ash Pond Closure Regulatory Asset (A)										9,532,606	9,985,123	10,522,731	11,167,690	
6	Net Investment (Lines 2 + 3 + 4)	12,686,826	16,727,351	20,054,855	34,017,878	33,926,750	37,470,666	41,447,184	46,052,888	48,804,997	53,088,200	61,004,066	65,180,041	69,080,149	
7	Average Net Investment		14,707,088	18,391,103	27,036,367	33,972,314	35,698,708	39,458,925	43,750,036	47,428,942	50,946,598	57,046,133	63,092,054	67,130,095	
8	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		67,961	84,985	124,935	156,986	164,964	182,340	203,656	220,782	237,156	265,550	293,694	309,067	2,312,076
	b Debt Component (Line 6 x Debt Component x 1/12)		16,795	21,003	30,876	38,796	40,768	45,062	50,838	55,112	59,200	66,288	73,313	78,005	576,056
9	Investment Expenses														
	a Depreciation (E)		6,221	6,221	7,162	10,359	22,936	33,996	35,447	37,195	37,811	37,420	38,017	39,614	312,398
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	658,328
	d Property Taxes		4,917	4,917	4,917	4,917	4,917	4,917	4,917	4,917	4,917	4,917	4,917	4,917	59,005
	e Other (G)		0	0	0	0	0	0	0	0	0	452,517	537,608	644,959	1,635,084
10	Total System Recoverable Expenses (Lines 7 + 8)		150,755	171,986	222,750	265,919	288,445	321,175	349,719	372,867	393,945	429,036	464,801	486,464	3,917,862
	a Recoverable Costs Allocated to Energy		11,597	13,230	17,135	20,455	22,188	24,706	26,901	28,682	30,303	33,003	35,754	37,420	301,374
	b Recoverable Costs Allocated to Demand		139,159	158,757	205,616	245,464	266,257	296,469	322,817	344,185	363,642	396,033	429,047	449,043	3,616,488
11	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
12	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
13	Retail Energy-Related Recoverable Costs (H)		11,287	12,893	16,701	19,952	21,627	24,142	26,242	27,966	29,551	32,164	34,765	36,371	293,661
14	Retail Demand-Related Recoverable Costs (I)		135,238	154,284	199,823	238,549	258,756	288,117	313,723	334,488	353,397	384,876	416,960	436,393	3,514,603
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		146,525	167,177	216,524	258,500	280,383	312,260	339,964	362,454	382,948	417,040	451,724	472,764	3,808,264

Notes:
(A) Adjustments were made in September 2019 to reclassify Plant Scholz and portions of Plant Smith pond closure plant and CWIP balances to a regulatory asset.
(B) Beginning Balances: Crist $441,896; Smith $528,323; Scherer $1,550,297; Scholz $673,181; Daniel $104,724. Ending Balances: Crist $790,872; Smith $2,601,638; Scherer $16,088,112; Scholz $0,000; Daniel $104,724.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Investment expenses realted to Plant Smith and Scholz reclass
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Steam Electric Effluent Limitations Guidelines

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	60,336	560,173	417,093	1,037,601
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	384,575	384,575
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	5,657,885	5,657,885	5,657,885	5,657,885	5,657,885	5,657,885	5,657,885	5,657,885	5,657,885	5,657,885	5,657,885	5,657,885	6,042,460	
3	Less: Accumulated Depreciation (C)	(185,787)	(204,458)	(223,129)	(241,800)	(260,471)	(279,142)	(297,813)	(316,484)	(335,155)	(353,826)	(372,497)	(391,357)	(410,569)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	60,336	620,509	653,027	
5	Net Investment (Lines 2 + 3 + 4) (A)	5,472,099	5,453,428	5,434,757	5,416,086	5,397,414	5,378,743	5,360,072	5,341,401	5,322,730	5,304,059	5,345,724	5,887,037	6,284,918	
6	Average Net Investment		5,462,763	5,444,092	5,425,421	5,406,750	5,388,079	5,369,408	5,350,737	5,332,066	5,313,395	5,324,892	5,616,381	6,085,978	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		25,243	25,157	25,071	24,985	24,898	24,812	24,908	24,821	24,734	24,787	26,144	28,020	303,580
	b Debt Component (Line 6 x Debt Component x 1/12)		6,238	6,217	6,196	6,175	6,153	6,132	6,218	6,196	6,174	6,188	6,526	7,072	75,484
8	Investment Expenses														
	a Depreciation (E)		18,671	18,671	18,671	18,671	18,671	18,671	18,671	18,671	18,671	18,671	18,860	19,212	224,782
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		50,153	50,045	49,938	49,830	49,723	49,615	49,796	49,688	49,579	49,646	51,530	54,304	603,846
	a Recoverable Costs Allocated to Energy		3,858	3,850	3,841	3,833	3,825	3,817	3,830	3,822	3,814	3,819	3,964	4,177	46,450
	b Recoverable Costs Allocated to Demand		46,295	46,196	46,096	45,997	45,898	45,798	45,966	45,866	45,765	45,827	47,566	50,127	557,397
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		3,755	3,752	3,744	3,739	3,728	3,729	3,737	3,727	3,719	3,722	3,854	4,060	45,266
13	Retail Demand-Related Recoverable Costs (I)		44,991	44,894	44,798	44,701	44,605	44,508	44,671	44,573	44,476	44,536	46,226	48,714	541,694
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		48,746	48,646	48,542	48,440	48,333	48,238	48,407	48,300	48,195	48,258	50,080	52,775	586,959

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: 316(b) Intake Structure Regulation

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	5,607	1,028	1,779	1,049	1,698	39	1,780	305,723	318,704
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	561	103	178	105	170	4	178	28,130	29,428
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	561	664	841	946	1,116	1,120	1,298	29,428	
4	CWIP - Non Interest Bearing	0	0	0	0	0	5,607	6,636	8,415	9,464	11,162	11,201	12,981	318,704	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	6,168	7,299	9,256	10,410	12,278	12,321	14,279	348,132	
6	Average Net Investment		0	0	0	0	3,084	6,734	8,278	9,833	11,344	12,300	13,300	181,205	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	14	31	39	46	53	57	62	834	1,136
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	4	8	10	11	13	14	15	211	286
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	18	39	48	57	66	72	77	1,045	1,422
	a Recoverable Costs Allocated to Energy		0	0	0	0	1	3	4	4	5	6	6	80	109
	b Recoverable Costs Allocated to Demand		0	0	0	0	16	36	44	53	61	66	71	964	1,312
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	1	3	4	4	5	5	6	78	106
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	16	35	43	51	59	64	69	937	1,275
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	17	38	47	56	64	70	75	1,015	1,382

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	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 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	Average Net Working Capital Balance		0	0	0	0	0	0	0	0	0	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Mercury Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 2A
(E) Line 8 is reported on Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Working Capital, Annual NOx Expenses
For Project: Annual NOx Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	7,025	7,025	7,025	6,653	6,653	6,653	6,653	6,128	6,128	6,128	5,768	5,768	5,768	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	7,025	7,025	7,025	6,653	6,653	6,653	6,653	6,128	6,128	6,128	5,768	5,768	5,768	
4	Average Net Working Capital Balance		7,025	7,025	6,839	6,653	6,653	6,653	6,391	6,128	6,128	5,948	5,768	5,768	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		32	32	32	31	31	31	30	29	29	28	27	27	357
	b Debt Component (Line 4 x Debt Component x 1/12)		8	8	8	8	8	8	7	7	7	7	7	7	89
6	Total Return Component (D)		40	40	39	38	38	38	37	36	36	35	34	33	445
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual NOx Allowance Expense		0	0	372	0	0	0	525	0	0	361	0	0	1,257
8	Net Expenses (E)		0	0	372	0	0	0	525	0	0	361	0	0	1,257
9	Total System Recoverable Expenses (Lines 6 + 8)		40	40	411	38	38	38	562	36	36	396	34	33	1,703
	a Recoverable Costs Allocated to Energy		3	3	375	3	3	3	527	3	3	364	3	3	1,292
	b Recoverable Costs Allocated to Demand		37	37	36	35	35	35	34	33	33	32	31	31	411
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		3	3	365	3	3	3	514	3	3	354	3	2	1,259
13	Retail Demand-Related Recoverable Costs (C)		36	36	35	34	34	34	33	32	32	31	30	30	399
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		39	39	401	37	37	37	548	35	35	385	33	32	1,659

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 2A
(E) Line 8 is reported on Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal NOx Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	8,181	8,181	8,181	8,181	8,181	8,181	8,181	6,212	6,212	6,212	2,917	2,917	2,917	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	8,181	8,181	8,181	8,181	8,181	8,181	8,181	6,212	6,212	6,212	2,917	2,917	2,917	
4	Average Net Working Capital Balance		8,181	8,181	8,181	8,181	8,181	8,181	7,197	6,212	6,212	4,565	2,917	2,917	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		38	38	38	38	38	38	33	29	29	21	14	13	366
	b Debt Component (Line 4 x Debt Component x 1/12)		9	9	9	9	9	9	8	7	7	5	3	3	91
6	Total Return Component (D)		47	47	47	47	47	47	42	36	36	27	17	17	457
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Seasonal NOx Allowance Expense		0	0	0	0	0	0	1,969	0	0	3,295	0	0	5,264
8	Net Expenses (E)		0	0	0	0	0	0	1,969	0	0	3,295	0	0	5,264
9	Total System Recoverable Expenses (Lines 6 + 8)		47	47	47	47	47	47	2,011	36	36	3,322	17	17	5,721
	a Recoverable Costs Allocated to Energy		4	4	4	4	4	4	1,972	3	3	3,297	1	1	5,299
	b Recoverable Costs Allocated to Demand		44	44	44	44	44	44	39	33	33	25	16	16	422
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		4	4	4	4	4	4	1,924	3	3	3,213	1	1	5,166
13	Retail Demand-Related Recoverable Costs (C)		42	42	42	42	42	42	38	32	32	24	15	15	410
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		46	46	46	46	46	46	1,961	35	35	3,237	16	16	5,577

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 2E
(E) Line 8 is reported on Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	68	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	6,314,539	6,314,539	6,314,539	6,312,336	6,312,336	6,312,336	6,312,336	6,309,606	6,309,606	6,309,606	6,302,888	6,302,888	6,302,888	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(268)	(268)	(268)	(268)	(268)	(268)	(249)	(234)	(220)	(205)	(190)	(176)	(161)	
3	Total Working Capital Balance	6,314,271	6,314,271	6,314,271	6,312,067	6,312,067	6,312,067	6,312,087	6,309,372	6,309,387	6,309,401	6,302,698	6,302,712	6,302,727	
4	Average Net Working Capital Balance		6,314,271	6,314,271	6,313,169	6,312,067	6,312,067	6,312,077	6,310,729	6,309,379	6,309,394	6,306,050	6,302,705	6,302,720	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		29,178	29,178	29,173	29,168	29,168	29,168	29,376	29,370	29,370	29,355	29,339	29,018	350,862
	b Debt Component (Line 4 x Debt Component x 1/12)		7,211	7,211	7,210	7,208	7,208	7,208	7,333	7,331	7,332	7,328	7,324	7,324	87,228
6	Total Return Component (D)		36,389	36,389	36,383	36,376	36,376	36,377	36,710	36,702	36,702	36,682	36,663	36,341	438,090
7	Expenses														
	a Gains		0	0	0	0	0	(88)	(15)	(15)	(15)	(15)	(15)	(15)	(175)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		0	0	2,204	0	0	0	2,729	0	0	6,718	0	0	11,651
8	Net Expenses (E)		0	0	2,204	0	0	(88)	2,715	(15)	(15)	6,703	(15)	(15)	11,476
9	Total System Recoverable Expenses (Lines 6 + 8)		36,389	36,389	38,587	36,376	36,376	36,289	39,424	36,687	36,687	43,386	36,648	36,327	449,566
	a Recoverable Costs Allocated to Energy		2,799	2,799	5,002	2,798	2,798	2,711	5,538	2,809	2,809	9,525	2,806	2,781	45,175
	b Recoverable Costs Allocated to Demand		33,590	33,590	33,584	33,578	33,578	33,578	33,886	33,878	33,879	33,861	33,843	33,546	404,391
10	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
11	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		2,724	2,728	4,876	2,729	2,727	2,649	5,403	2,738	2,739	9,283	2,728	2,703	44,028
13	Retail Demand-Related Recoverable Costs (C)		32,644	32,644	32,638	32,632	32,632	32,632	32,931	32,924	32,924	32,907	32,889	32,601	392,998
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		35,368	35,372	37,514	35,362	35,360	35,281	38,334	35,663	35,663	42,190	35,617	35,304	437,026

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 2E
(E) Line 8 is reported on Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019
Return on Working Capital, Amortization Expense
For Project: Regulatory Asset Smith Units 1 & 2

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Regulatory Asset Balance 182.2 (B)	19,921,306	19,921,306	19,802,726	19,684,147	19,565,568	19,446,989	19,328,410	19,209,830	19,091,251	18,972,672	18,854,093	18,735,514	18,616,934	
2	Less Amortization (C)	0	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	
3	Net Regulatory Asset Balance (Lines 1 + 2) (A)	19,921,306	19,802,726	19,684,147	19,565,568	19,446,989	19,328,410	19,209,830	19,091,251	18,972,672	18,854,093	18,735,514	18,616,934	18,498,355	
4	Average Regulatory Asset Balance		19,862,016	19,743,437	19,624,858	19,506,278	19,387,699	19,269,120	19,150,541	19,031,962	18,913,382	18,794,803	18,676,224	18,557,645	
5	Returun on Average Regulatoy Asset Balance														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		91,782	91,234	90,686	90,139	89,591	89,043	89,146	88,594	88,042	87,490	86,938	85,439	1,068,123
	b Debt Component (Line 6 x Debt Component x 1/12)		22,682	22,547	22,412	22,276	22,141	22,005	22,253	22,115	21,977	21,840	21,702	21,564	265,514
6	Amortization Expense														
	a Amortization (E)		118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	1,422,950
	b Other (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total System Recoverable Expenses (Lines 5 + 6)		233,044	232,361	231,677	230,994	230,311	229,627	229,978	229,288	228,598	227,909	227,219	225,583	2,756,588
	a Recoverable Costs Allocated to Energy		17,926	17,874	17,821	17,769	17,716	17,664	17,691	17,638	17,584	17,531	17,478	17,353	212,045
	b Recoverable Costs Allocated to Demand		215,118	214,487	213,856	213,225	212,594	211,964	212,287	211,651	211,014	210,377	209,740	208,230	2,544,543
8	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
9	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
10	Retail Energy-Related Recoverable Costs (G)		17,448	17,419	17,370	17,331	17,268	17,261	17,257	17,197	17,148	17,086	16,995	16,866	206,646
11	Retail Demand-Related Recoverable Costs (H)		209,057	208,444	207,831	207,218	206,605	205,992	206,307	205,688	205,069	204,450	203,832	202,364	2,472,857
12	Total Jurisdictional Recoverable Costs (Lines 10 + 11)		226,505	225,864	225,202	224,549	223,873	223,253	223,563	222,885	222,217	221,536	220,826	219,230	2,679,503

Notes:
(A) End of period Regulatory Asset Balance.
(B) Beginning of period Regulatory Asset Balance.
(C) Regulatory Asset has a 15 year amortization period.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Regulatory Asset has a 15 year amortization period.
(F) Description and reason for "Other" adjustments to regulatory asset.
(G) Line 7a x Line 8 x line loss multiplier
(H) Line 7b x Line 9.

Schedule 9A
Page 1 of 3

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - June 2019

FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Amount ($000s)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	826,744	34.2628	3.89	1.3328	1.3328	
2	Short-Term Debt	9,317	0.3861	4.17	0.0161	0.0161	
3	Preferred Stock	7,010	0.2905	6.14	0.0178	0.0238	
4	Common Stock	969,929	40.1968	10.25	4.1202	5.5190	
5	Customer Deposits	22,436	0.9298	2.29	0.0213	0.0213	
6	Deferred Taxes	576,770	23.9031				
7	Investment Tax Credit	741	0.0307	7.39	0.0023	0.0028	
8	Total	2,412,949	100.0000		5.5105	6.9158	0.5763
	ITC Component:						
9	Debt	826,744	45.8364	3.89	1.7830	0.0005	
10	Equity-Preferred	7,010	0.3887	6.14	0.0239	0.0000	
11	-Common	969,929	53.7749	10.25	5.5119	0.0023	
12		1,803,684	100.0000		7.3188	0.0028	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.3707	0.1142
14	Total Equity Component (Lines 3, 4, 10, and 11)					5.5451	0.4621
15	Total Revenue Requirement Rate of Return					6.9158	0.5763

Column:
(1) Based on the May 2018 Surveillance Report, Schedule 4
Adjusted to achieve the 53.5% equity ratio as prescribed in the 2018 Tax Reform Settlement Agreement in Docket No. 20180039-EI.
(2) Column (1) / Total Column (1)
(3) Based on the May 2018 Surveillance Report, Schedule 4.
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.25345); 25.3450% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

Schedule 9A
Page 2 of 3

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
July 2019 - November 2019

FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Amount ($000s)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	894,848	34.5417	3.91	1.3519	1.3519	
2	Short-Term Debt	20,976	0.8097	2.96	0.0240	0.0240	
3	Preferred Stock	0	0.0000	0.00	0.0000	0.0000	
4	Common Stock	1,053,681	40.6728	10.25	4.1690	5.5844	
5	Customer Deposits	22,119	0.8538	2.08	0.0178	0.0178	
6	Deferred Taxes	598,399	23.0986				
7	Investment Tax Credit	608	0.0235	7.34	0.0017	0.0021	
8	Total	2,590,631	100.0000		5.5644	6.9802	0.5817
	ITC Component:						
9	Debt	894,848	45.9243	3.91	1.7974	0.0004	
10	Equity-Preferred	0	0.0000	0.00	0.0000	0.0000	
11	-Common	1,053,681	54.0757	10.25	5.5428	0.0017	
12		1,948,530	100.0000		7.3402	0.0021	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.3941	0.1162
14	Total Equity Component (Lines 3, 4, 10, and 11)					5.5861	0.4655
15	Total Revenue Requirement Rate of Return					6.9802	0.5817

Column:

(1) Based on the Revised May 2019 Surveillance Report, Schedule 4
Adjusted to achieve the 53.5% equity ratio as prescribed in the 2018 Tax Reform Settlement Agreement in Docket No. 20180039-EI.

(2) Column (1) / Total Column (1)

(3) Based on the Revised May 2019 Surveillance Report, Schedule 4.

(4) Column (2) x Column (3)

(5) For equity components: Column (4) / (1-.25345); 25.345% = effective income tax rate
For debt components: Column (4)

(6) Column (5) / 12

Schedule 9A

Revised 9-25-19

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
December 2019

FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	894,848	34.5416	3.91	1.3519	1.3519	
2	Short-Term Debt	20,976	0.8097	2.96	0.0240	0.0240	
3	Preferred Stock	0	0.0000	0.00	0.0000	0.0000	
4	Common Stock	1,053,681	40.6728	10.25	4.1690	5.5234	
5	Customer Deposits	22,119	0.8538	2.08	0.0178	0.0178	
6	Deferred Taxes	598,399	23.0986				
7	Investment Tax Credit	608	0.0235	7.34	0.0017	0.0021	
8	Total	2,590,631	100.0000		5.5644	6.9192	0.5766
	ITC Component:						
9	Debt	894,848	45.9243	3.91	1.7974	0.0004	
10	Equity-Preferred	0	0.0000	0.00	0.0000	0.0000	
11	-Common	1,053,681	54.0757	10.25	5.5428	0.0017	
12		1,948,530	100.0000		7.3402	0.0021	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.3941	0.1162
14	Total Equity Component (Lines 3, 4, 10, and 11)					5.5251	0.4604
15	Total Revenue Requirement Rate of Return					6.9192	0.5766

Column:

(1) Based on the May 2019 Surveillance Report, Schedule 4.
Adjusted to achieve the 53.5% equity ratio as prescribed in the 2018 Tax Reform Settlement Agreement in Docket No. 20180039-EI.
(2) Column (1) / Total Column (1)
(3) Based on the May 2019 Surveillance Report, Schedule 4.
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.245218); 24.5218% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2019 - December 2019

For Project: Scherer - Air Quality Compliance and CCR Programs
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	510,075	549,187	1,015,434	703,431	1,466,131	549,731	684,240	1,166,956	936,383	1,299,359	2,775,800	11,656,725
	b Clearings to Plant		0	5,095	37,092	1,262	11,422,390	1,117,528	178,450	117,280	257,576	32,701	51,247	2,249,987	15,470,607
	c Retirements		0	0	0	0	0	0	0	0	85,265	0	0	549,028	634,293
	d Other		0	276,023	210,306	1,073,665	960,882	1,515	593	14	42	398,769	11,146	145,587	3,078,542
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base	184,504,377	184,504,377	184,509,472	184,546,564	184,547,825	195,970,215	197,158,297	197,336,747	197,454,028	197,626,339	197,659,039	197,710,286	199,411,245	
3	Less: Accumulated Depreciation	(28,431,526)	(28,765,225)	(28,822,904)	(28,946,339)	(28,206,450)	(27,589,624)	(27,943,515)	(28,299,559)	(28,656,447)	(28,928,302)	(28,886,881)	(29,239,720)	(28,910,698)	
4	Working Capital (Emissions)	16,303	16,303	16,303	15,924	15,924	15,924	15,924	15,371	15,371	15,371	14,998	14,998	14,998	
5	CWIP - Non Interest Bearing	16,995,494	16,995,494	17,500,474	18,012,569	19,026,741	8,307,782	8,656,385	9,027,666	9,594,626	10,504,005	11,407,688	12,655,800	13,181,613	
6	Net Investment (Lines 2 + 3 + 4 + 5)	173,084,647	172,750,949	173,203,344	173,628,717	175,384,041	176,704,297	177,887,091	178,080,226	178,407,578	179,217,413	180,194,845	181,141,364	183,697,158	
7	Average Net Investment		172,917,798	172,977,147	173,416,031	174,506,379	176,044,169	177,295,694	177,983,659	178,243,902	178,812,496	179,706,129	180,668,104	182,419,261	
8	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12)		799,053	799,327	801,355	806,394	813,500	819,283	828,514	829,725	832,372	836,532	841,010	839,858	9,846,925
	b Debt Component (Line 6 x Debt Component x 1/12)		197,472	197,540	198,041	199,286	201,042	202,472	206,817	207,119	207,780	208,819	209,936	211,971	2,448,296
9	Investment Expenses														
	a Depreciation		330,678	330,683	330,721	330,756	341,037	352,386	353,616	353,882	354,143	354,327	360,966	362,572	4,155,768
	b Amortization		247	247	247	247	247	247	247	247	247	247	247	247	2,966
	c Dismantlement		2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	2,773	33,273
	d Property Taxes		44,221	44,221	44,221	44,221	44,221	44,221	44,221	44,221	44,221	44,221	44,221	44,221	530,651
	e Other		0	0	0	0	0	0	0	0	0	0	0	0	0
10	O&M and Emissions														
	a O&M Expense		87,420	308,829	401,762	85,521	321,081	181,336	198,423	135,706	135,394	101,780	130,894	94,379	2,182,524
	b Emissions Expense		0	0	481	0	0	0	1,351	0	0	997	0	0	2,829
11	Total System Recoverable Expenses (Lines 8 + 9 + 10)		1,461,864	1,683,620	1,779,602	1,469,197	1,723,901	1,602,718	1,635,961	1,573,674	1,576,930	1,549,695	1,590,047	1,556,021	19,203,232
	a Recoverable Costs Allocated to Energy		192,834	414,438	504,562	178,620	431,022	284,891	311,070	244,527	243,810	213,651	242,782	203,359	3,465,565
	b Recoverable Costs Allocated to Demand		1,269,031	1,269,182	1,275,040	1,290,577	1,292,879	1,317,828	1,324,891	1,329,147	1,333,120	1,336,045	1,347,265	1,352,662	15,737,667
12	Energy Jurisdictional Factor		0.9721248	0.9734038	0.9735284	0.9742054	0.9735243	0.9760212	0.9743031	0.9738659	0.9740161	0.9734158	0.9711614	0.9708045	
13	Demand Jurisdictional Factor		0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
14	Retail Energy-Related Recoverable Costs		187,683	403,900	491,795	174,221	420,114	278,393	303,440	238,422	237,760	208,221	236,064	197,659	3,377,672
15	Retail Demand-Related Recoverable Costs		1,233,279	1,233,427	1,239,119	1,254,219	1,256,456	1,280,701	1,287,566	1,291,702	1,295,563	1,298,405	1,309,309	1,314,554	15,294,300
16	Total Jurisdictional Recoverable Costs (Lines 14 + 15)		1,420,962	1,637,326	1,730,914	1,428,440	1,676,570	1,559,094	1,591,006	1,530,124	1,533,322	1,506,626	1,545,373	1,512,213	18,671,972
17	Scherer/Flint Credit(24%)		341,031	392,958	415,419	342,826	402,377	374,183	381,841	367,230	367,997	361,590	370,890	362,931	4,481,273

Notes:
(A) Adjustments were made in June 2019 to the plant balance in the amount of $70,554 due to synchronization with the NEE accounting system at the retirement unit level.

APPENDIX I

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-9E

JANUARY 2020 - DECEMBER 2020
ACTUAL/ESTIMATED TRUE-UP

RLH-2
DOCKET NO. 20200007-EI
EXHIBIT _____
PAGES 1-44
JULY 31, 2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 16
PARTY: RLH-2
DESCRIPTION: Environmental Cost Recovery Actual/Estimated True-up January 2020 - December 2020 Commission Forms 4...

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-1E

JANUARY 2020 THROUGH DECEMBER 2020

	2020
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$2,788,240
2. Interest Provision (Form 42-3E, Line 10)	$47,030
3. Sum of Current Period Adjustments (Form 42-2E, Line 10)	$1,889
4. Actual/Estimated True-up to be refunded/(recovered)	$2,837,159

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-2E

January 2020 - December 2020

	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1. ECRC Revenues (Net of Revenue Taxes)	$13,111,890	$11,731,758	$12,146,163	$12,671,424	$14,987,254	$17,596,186	$19,263,843	$19,041,859	$16,553,093	$13,951,673	$12,159,705	$13,591,194	$176,806,042
2. True-Up Provision (Order No. PSC-2018-0594-FOF-EI)	$542,141	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$542,142	$6,505,703
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$13,654,031	$12,273,900	$12,688,305	$13,213,566	$15,529,396	$18,138,328	$19,805,985	$19,584,001	$17,095,235	$14,493,815	$12,701,847	$14,133,336	$183,311,745
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5E-2, Line 9)	$2,020,448	$1,457,563	$2,492,770	$1,286,152	$3,163,769	$2,038,613	($1,075)	$2,221,442	$1,950,127	$2,041,781	$3,408,911	$2,019,681	$24,100,184
b. Capital Investment Projects (Form 42-7E-2, Line 8)	$12,815,145	$12,931,396	$13,036,933	$12,934,907	$12,923,511	$12,825,770	$13,017,232	$13,060,447	$13,093,822	$13,161,652	$13,272,477	$13,350,029	$156,423,321
c. Total Jurisdictional ECRC Costs	$14,835,593	$14,388,959	$15,529,703	$14,221,060	$16,087,280	$14,864,382	$13,016,158	$15,281,889	$15,043,949	$15,203,433	$16,681,388	$15,369,710	$180,523,505
5 Over/(Under) Recovery (Line 3 - Line 4c)	($1,181,561)	($2,115,059)	($2,841,398)	($1,007,494)	($557,884)	$3,273,945	$6,789,827	$4,302,112	$2,051,286	($709,618)	($3,979,541)	($1,236,374)	$2,788,240
6 Interest Provision (Schedule 3E, Line 10)	$15,527	$12,478	$9,980	$3,688	$149	$227	$528	$863	$1,040	$1,049	$855	$644	$47,030
7 Prior Period True-Up to be (Collected)/Refunded	$6,505,703	$4,797,528	$2,152,804	($1,218,867)	($2,764,815)	($3,864,692)	($1,132,661)	$5,115,552	$8,876,385	$10,386,569	$9,135,858	$4,615,030	$6,505,703
a. Deferred True-Up (Form 42-1A, Line 7)	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	$5,891,843	
8 True-Up Collected/(Refunded) (see Line 2)	($542,141)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($542,142)	($6,505,703)
9 End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	$10,689,370	$8,044,647	$4,671,087	$3,127,027	$2,027,151	$4,759,181	$11,007,395	$14,768,228	$16,278,412	$15,027,701	$10,506,873	$8,729,001	$2,835,270
10 Adjustments to Period Total True-Up Including Interest	$0	$0	$1,889	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,889
11 End of Period Total True-Up (Lines 9 + 10)	$10,689,370	$8,044,647	$4,672,976	$3,127,027	$2,027,151	$4,759,181	$11,007,395	$14,768,228	$16,278,412	$15,027,701	$10,506,873	$8,729,001	$2,837,159

Notes:
The adjustment in March 2020 are carrying costs related to the deferred amortization for the reclassification associated with Plant Smith and Plant Scholz pond closure projects

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-3E

January 2020 - December 2020

	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1 Beg. True-Up Amount (Form 42-2E, Lines 7 + 7a)	$12,397,546	$10,689,370	$8,044,647	$4,672,976	$3,127,027	$2,027,151	$4,759,181	$11,007,395	$14,768,228	$16,278,412	$15,027,701	$10,506,873	
2 Ending True-Up Amount Before Interest	$10,673,843	$8,032,169	$4,661,107	$3,123,340	$2,027,001	$4,758,954	$11,006,867	$14,767,364	$16,277,372	$15,026,652	$10,506,017	$8,728,357	
3 Total of Beginning & Ending True-up (Lines 1 + 2)	$23,071,389	$18,721,539	$12,705,754	$7,796,315	$5,154,029	$6,786,104	$15,766,048	$25,774,759	$31,045,600	$31,305,064	$25,533,718	$19,235,230	
4 Average True-Up Amount (Line 3 x 1/2)	$11,535,694	$9,360,770	$6,352,877	$3,898,158	$2,577,014	$3,393,052	$7,883,024	$12,887,380	$15,522,800	$15,652,532	$12,766,859	$9,617,615	
5 Interest Rate (First Day of Reporting Business Month)[1]	1.59000%	1.64000%	1.56000%	2.21000%	0.06000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	
6 Interest Rate (First Day of Subsequent Business Month)[1]	1.64000%	1.56000%	2.21000%	0.06000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	
7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6	3.23000%	3.20000%	3.77000%	2.27000%	0.14000%	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	
8 Average Interest Rate (Line 7 x 1/2)	1.61500%	1.60000%	1.88500%	1.13500%	0.07000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	0.08000%	
9 Monthly Average Interest Rate (Line 8 x 1/12)	0.13460%	0.13330%	0.15710%	0.09460%	0.00580%	0.00670%	0.00670%	0.00670%	0.00670%	0.00670%	0.00670%	0.00670%	
10 Interest Provision for the Month (Line 4 x Line 9)	$15,527	$12,478	$9,980	$3,688	$149	$227	$528	$863	$1,040	$1,049	$855	$644	$47,030

Notes:
1 Actual interest rates are developed using the AA financial 30-day rates as published by the Federal Reserve. Estimated interest rates are based on the actual rates for May 2020.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-4E

JANUARY 2020 THROUGH DECEMBER 2020

VARIANCE REPORT OF O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)
O&M PROJECT #	ECRC - 2020 Actual Estimated Filing [a]	ECRC - 2020 Projection Filing [b]	Dif ECRC - 2020 Projection Filing [c]	% Dif ECRC - Projection Filing [d]
1 - Sulfur	$0	$0	$0	
2 - Air Emission Fees	$270,737	$285,269	($14,532)	(5.1%)
3 - Title V	$217,024	$231,465	($14,441)	(6.2%)
4 - Asbestos Fees	$1,000	$1,000	$0	0.0%
5 - Emission Monitoring	$688,542	$736,399	($47,858)	(6.5%)
6 - General Water Quality	$1,257,915	$1,542,559	($284,645)	(18.5%)
7 - Groundwater Contamination Investigation	$2,091,013	$2,241,964	($150,951)	(6.7%)
8 - State NPDES Administration	$49,516	$35,000	$14,516	41.5%
9 - Lead and Copper Rule	$0	$0	$0	
10 - Env Auditing/Assessment	$2,588	$15,000	($12,412)	(82.7%)
11 - General Solid & Hazardous Waste	$957,980	$968,840	($10,860)	(1.1%)
12 - Above Ground Storage Tanks	$196,679	$183,659	$13,020	7.1%
13 - Low NOx	$0	$0	$0	
14 - Ash Pond Diversion Curtains	$0	$0	$0	
15 - Mercury Emissions	$0	$0	$0	
16 - Sodium Injection	$0	$0	$0	
17 - Gulf Coast Ozone Study	$0	$0	$0	
18 - SPCC Substation Project	$0	$0	$0	
19 - FDEP NOx Reduction Agreement	$227,320	$560,731	($333,411)	(59.5%)
20 - Air Quality Compliance Program	$16,998,777	$18,287,138	($1,288,361)	(7.0%)
21 - MACT ICR	$0	$0	$0	
22 - Crist Water Conservation	$208,487	$45,978	$162,508	353.4%
23 - Coal Combustion Residual	$1,000,844	$6,866,072	($5,865,228)	(85.4%)
24 - Smith Water Conservation	$36,806	$48,696	($11,890)	(24.4%)
25 - Mercury Allowances	$0	$0	$0	
26 - Annual NOx Allowances	$1,362	$3,087	($1,725)	(55.9%)
27 - Seasonal NOx Allowances	$1,545	$7,113	($5,568)	(78.3%)
28 - SO2 Allowances	$30,417	$9,834	$20,583	209.3%
Total	$24,238,551	$32,069,805	($7,831,254)	(24.4%)

[a] The 12-Month Totals on Form 42-5E
[b] As approved in Order No. PSC-2019-0500-FOF-EI issued November 22, 2019
[c] Column (2) - Column (3)
[d] Column (4) / Column (3)

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-5E

JANUARY 2020 THROUGH DECEMBER 2020

O&M ACTIVITIES

Line	O & M Project	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Amount	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
1	Sulfur	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Air Emission Fees	$3,475	($6,635)	$137,213	$16,883	$11,153	($34,821)	$12,976	$12,976	$12,976	$12,976	$12,976	$78,587	$270,737	$0	$270,737
3	Title V	$12,225	$21,892	$18,269	$16,531	$13,808	$17,757	$23,526	$16,987	$17,757	$17,757	$16,987	$23,530	$217,024	$0	$217,024
4	Asbestos Fees	$2,329	$1,000	$51,500	($18)	$733	($54,543)	$0	$0	$0	$0	$0	$0	$1,000	$1,000	$0
5	Emission Monitoring	$46,081	$40,695	$41,240	$60,469	$88,633	$50,350	$91,108	$52,876	$53,173	$53,048	$53,048	$57,819	$688,542	$0	$688,542
6	General Water Quality	($67,189)	$80,089	$121,111	$47,195	$88	$125,226	$153,164	$170,590	$154,187	$201,001	$166,923	$105,527	$1,257,915	$1,257,915	$0
7	Groundwater Contamination Investigation	$219,935	$175,562	$189,139	$247,262	$398,113	$125,498	$153,015	$100,498	$126,498	$126,498	$126,498	$102,498	$2,091,013	$2,091,013	$0
8	State NPDES Administration	$3,020	$3,120	$16,727	$14,246	$16,326	($38,423)	$0	$0	$0	$0	$0	$34,500	$49,516	$49,516	$0
9	Lead & Copper Rule	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Environmental Auditing/Assessment	($4,912)	$0	$0	$0	$28,500	($26,000)	$0	$0	$0	$2,500	$2,500	$0	$2,588	$2,588	$0
11	General Solid & Hazardous Waste	$116,157	$103,716	$15,721	$61,184	$52,120	$95,146	$86,808	$117,192	$101,754	$91,282	$71,545	$45,352	$957,980	$957,980	$0
12	Above Ground Storage Tanks	$6,447	$11,325	$8,149	$18,811	$12,166	$34,190	$20,000	$4,000	$36,000	$33,590	$6,000	$6,000	$196,679	$196,679	$0
13	Low NOx	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Ash Pond Diversion Curtains	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Mercury Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Sodium Injection	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Gulf Coast Ozone Study	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	SPCC Substation Project	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	FDEP NOx Reduction Agreement	$78,137	$5,299	($23,349)	$3,073	$3,309	$26,727	$38,979	$45,366	$37,999	$3,927	$3,927	$3,927	$227,320	$0	$227,320
20	Air Quality Compliance Program	$1,147,480	$731,047	$1,745,060	$728,491	$1,120,104	$1,292,806	$1,575,768	$1,709,679	$1,310,422	$1,382,405	$2,829,096	$1,426,418	$16,998,777	$0	$16,998,777
21	MACT ICR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Crist Water Conservation	$0	$0	$0	$0	$16,509	$50,000	$67,000	$12,000	$12,000	$20,978	$30,000	$0	$208,487	$208,487	$0
23	Coal Combustion Residuals	$466,919	$304,789	$183,026	$65,932	$1,455,371	$386,462	($2,280,949)	($17,909)	$94,619	$105,504	$95,593	$141,487	$1,000,844	$1,000,844	$0
24	Smith Water Conservation	$4,254	$2,466	$2,933	($1,373)	$120	$4,058	$4,058	$4,058	$4,058	$4,058	$4,058	$4,058	$36,806	$36,806	$0
25	Mercury Allowances	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Annual NOx Allowances	$929	($286)	$0	$176	$0	$93	$81	$99	$87	$60	$58	$67	$1,362	$0	$1,362
27	Seasonal NOx Allowances	($24)	$0	$0	($32)	$0	$375	$417	$426	$383	$0	$0	$0	$1,545	$0	$1,545
28	SO2 Allowances	$4,293	$1,395	$0	$18,846	($5)	$1,491	$1,184	$1,193	$1,126	$622	$117	$155	$30,417	$0	$30,417
2	Total of O & M Activities	$2,039,556	$1,475,475	$2,506,739	$1,297,675	$3,217,047	$2,056,392	($52,865)	$2,230,033	$1,963,040	$2,056,207	$3,419,327	$2,029,926	$24,238,551	$5,802,827	$18,435,724
3	Recoverable Costs Allocated to Energy	$1,292,596	$793,407	$1,918,433	$844,436	$1,237,002	$1,354,777	$1,744,038	$1,839,603	$1,433,923	$1,470,796	$2,916,209	$1,590,503	$18,435,724		
4	Recoverable Costs Allocated to Demand	$746,960	$682,068	$588,306	$453,238	$1,980,046	$701,614	($1,796,903)	$390,429	$529,117	$585,411	$503,117	$439,423	$5,802,827		
5	Retail Energy Jurisdictional Factor (C)	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 (D)	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427			
7	Jurisdictional Energy Recoverable Costs (A)	$1,294,147	$794,359	$1,920,735	$845,449	$1,238,486	$1,356,403	$1,746,131	$1,841,811	$1,435,644	$1,472,561	$2,919,709	$1,592,412	$18,457,847		
8	Jurisdictional Demand Recoverable Costs (B)	$726,301	$663,204	$572,035	$440,703	$1,925,283	$682,210	($1,747,206)	$379,631	$514,483	$569,220	$489,203	$427,270	$5,642,337		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	$2,020,448	$1,457,563	$2,492,770	$1,286,152	$3,163,769	$2,038,613	($1,075)	$2,221,442	$1,950,127	$2,041,781	$3,408,911	$2,019,681	$24,100,184		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6
(C) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(D) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-6E

JANUARY 2020 THROUGH DECEMBER 2020

VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

Capital Project #	ECRC - 2020 Actual Estiimated Filing (a)	ECRC - 2020 Projection Filing (b)	Dif ECRC - 2020 Projection Filing (c)	% Dif ECRC - 2020 Projection Filing (d)
1 - Air Quality Assurance Testing	$17,141	$17,086	$55	0.3%
2 - Crist 5, 6 & 7 Precipitator Projects	$3,718,240	$3,713,837	$4,403	0.1%
3 - Crist 7 Flue Gas Conditioning	$104,389	$104,659	($270)	(0.3%)
4 - Low NOx Burners, Crist 6 & 7	$1,733,968	$1,742,469	($8,501)	(0.5%)
5 - CEMS - Plants Crist, & Daniel	$533,364	$530,306	$3,058	0.6%
6 - Substation Contamination Remediation	$415,526	$475,659	($60,133)	(12.6%)
7 - Raw Water Well Flowmeters - Plants Crist & Smith	$12,688	$12,648	$39	0.3%
8 - Crist Cooling Tower Cell	$37,035	$37,131	($96)	(0.3%)
9 - Crist Dechlorination System	$23,178	$23,055	$123	0.5%
10 - Crist Diesel Fuel Oil Remediation	$194	$3,704	($3,510)	(94.8%)
11 - Crist Bulk Tanker Unload Sec Contain Struc	$4,848	$4,812	$36	0.8%
12 - Crist IWW Sampling System	$2,822	$2,801	$21	0.8%
13 - Sodium Injection System	$20,996	$20,913	$82	0.4%
14 - Smith Stormwater Collection System	$165,602	$165,182	$421	0.3%
15 - Smith Waste Water Treatment Facility	$69,378	$70,151	($773)	(1.1%)
16 - Daniel Ash Management Project	$1,243,496	$1,262,109	($18,613)	(1.5%)
17 - Smith Water Conservation	$2,304,613	$3,153,816	($849,203)	(26.9%)
18 - Underground Fuel Tank Replacement	$0	$0	$0	
19 - Crist FDEP Agreement for Ozone Attainment	$10,386,786	$10,502,402	($115,615)	(1.1%)
20 - SPCC Compliance	$74,023	$73,763	$260	0.4%
21 - Crist Common FTIR Monitor	($860)	$4,383	($5,243)	(119.6%)
22 - Precipitator Upgrades for CAM Compliance	$1,098,475	$1,105,511	($7,035)	(0.6%)
23 - Plant Groundwater Contamination	$0	$0	$0	
24 - Crist Water Conservation	$1,723,370	$1,752,873	($29,503)	(1.7%)
25 - Plant NPDES Permit Compliance Projects	$1,112,903	$1,126,922	($14,018)	(1.2%)
26 - Air Quality Compliance Program	$122,344,829	$124,010,680	($1,665,851)	(1.3%)
27 - General Water Quality	$441,535	$410,718	$30,817	7.5%
28 - Coal Combustion Residual	$9,160,660	$7,501,752	$1,658,908	22.1%
29 - Steam Electric Effluent Limitations Guidelines	$669,659	$652,519	$17,139	2.6%
30 - 316(b) Cooling Water Intake Structure Regulation	$114,654	$211,791	($97,137)	(45.9%)
31 - Mercury Allowances	$0	$0	$0	
32 - Annual NOx Allowances	$336	$243	$94	38.6%
33 - Seasonal NOx Allowances	$904	$14,801	($13,897)	(93.9%)
34 - SO2 Allowances	$437,357	$438,794	($1,436)	(0.3%)
35 - Scherer/Flint Credit - Energy	($9,777)	$0	($9,777)	
36 - Scherer/Flint Credit - Demand	($117,327)	$0	($117,327)	
37 - Regulatory Asset Smith Units 1 & 2	$2,661,190	$2,664,546	($3,355)	(0.1%)
Total	$160,506,198	$161,812,035	($1,305,837)	(0.8%)

(a) The 12-Month Totals on Form 42-7E
(b) As approved in Order No. PSC-2019-0500-FOF-EI issued November 22, 2019
(c) Column (2) - Column (3)
(d) Column (4) / Column (3)

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ACTUAL / ESTIMATED TRUE-UP AMOUNT FOR THE PERIOD

FORM 42-7E

JANUARY 2020 THROUGH DECEMBER 2020

CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

Line	Capital Project[A]	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total	Method of Classification Demand	Method of Classification Energy
1	Description of Capital Investment Projects															
1	Air Quality Assurance Testing	$1,458	$1,452	$1,446	$1,440	$1,435	$1,429	$1,428	$1,422	$1,417	$1,411	$1,405	$1,399	$17,141	$15,823	$1,319
2	Crist 5, 6 & 7 Precipitator Projects	$312,197	$311,550	$310,903	$310,256	$309,609	$308,962	$310,764	$310,109	$309,455	$308,800	$308,145	$307,490	$3,718,240	$3,432,221	$286,018
3	Crist 7 Flue Gas Conditioning	$8,645	$8,645	$8,645	$8,645	$8,645	$8,645	$8,753	$8,753	$8,753	$8,753	$8,753	$8,753	$104,389	$96,359	$8,030
4	Low NOx Burners, Crist 6 & 7	$145,362	$145,095	$144,828	$144,561	$144,294	$144,027	$144,976	$144,706	$144,435	$144,165	$143,895	$143,624	$1,733,968	$1,600,586	$133,382
5	CEMS - Plants Crist & Daniel	$44,755	$44,668	$44,580	$44,492	$44,404	$44,317	$44,580	$44,491	$44,403	$44,314	$44,225	$44,136	$533,364	$492,336	$41,028
6	Substation Contamination Remediation	$33,937	$34,007	$33,968	$33,137	$32,395	$32,669	$34,677	$36,101	$36,137	$36,139	$36,171	$36,189	$415,526	$383,563	$31,964
7	Raw Water Well Flowmeters - Plants Crist & Smith	$1,070	$1,067	$1,064	$1,061	$1,058	$1,055	$1,059	$1,056	$1,054	$1,051	$1,048	$1,045	$12,688	$11,712	$976
8	Crist Cooling Tower Cell	$3,067	$3,067	$3,067	$3,067	$3,067	$3,067	$3,105	$3,105	$3,105	$3,105	$3,105	$3,105	$37,035	$34,186	$2,849
9	Crist Dechlorination System	$1,968	$1,960	$1,953	$1,946	$1,939	$1,931	$1,932	$1,925	$1,917	$1,910	$1,902	$1,895	$23,178	$21,395	$1,783
10	Crist Diesel Fuel Oil Remediation	($112)	($113)	($113)	($114)	($9)	$95	$95	$94	$94	$93	$93	$93	$194	$179	$15
11	Crist Bulk Tanker Unloading Secondary Containment	$414	$412	$410	$409	$407	$405	$403	$402	$400	$398	$396	$394	$4,848	$4,475	$373
12	Crist IWW Sampling System	$241	$240	$239	$238	$237	$236	$235	$234	$233	$231	$230	$229	$2,822	$2,605	$217
13	Sodium Injection System	$1,775	$1,769	$1,764	$1,758	$1,753	$1,748	$1,752	$1,746	$1,741	$1,735	$1,730	$1,724	$20,996	$19,381	$1,615
14	Smith Stormwater Collection System	$14,126	$14,064	$14,001	$13,939	$13,877	$13,814	$13,788	$13,725	$13,662	$13,599	$13,535	$13,472	$165,602	$152,864	$12,739
15	Smith Waste Water Treatment Facility	$5,141	$3,829	$2,551	$2,593	$5,753	$7,068	$7,110	$7,096	$7,081	$7,066	$7,052	$7,037	$69,378	$64,041	$5,337
16	Daniel Ash Management Project	$104,530	$104,314	$104,099	$103,883	$103,668	$103,453	$103,803	$103,585	$103,367	$103,149	$102,931	$102,713	$1,243,496	$1,147,843	$95,654
17	Smith Water Conservation	$192,306	$191,838	$190,786	$188,724	$191,108	$192,338	$193,427	$193,332	$193,182	$192,874	$192,514	$192,184	$2,304,613	$2,127,335	$177,278
18	Underground Fuel Tank Replacement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Crist FDEP Agreement for Ozone Attainment	$875,754	$874,289	$871,950	$869,611	$867,271	$864,074	$866,561	$864,192	$861,824	$859,455	$857,087	$854,718	$10,386,786	$9,587,803	$798,984
20	SPCC Compliance	$6,255	$6,236	$6,217	$6,198	$6,179	$6,160	$6,177	$6,158	$6,139	$6,120	$6,101	$6,081	$74,023	$68,329	$5,694
21	Crist Common FTIR Monitor	($191)	($191)	($191)	($191)	($96)	$0	$0	$0	$0	$0	$0	$0	($860)	($794)	($66)
22	Precipitator Upgrades for CAM Compliance	$92,733	$92,466	$92,199	$91,932	$91,665	$91,398	$91,690	$91,420	$91,149	$90,879	$90,608	$90,338	$1,098,475	$1,013,977	$84,498
23	Plant Groundwater Investigation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Crist Water Conservation	$145,606	$143,689	$141,277	$140,404	$143,336	$144,484	$145,068	$144,679	$144,290	$143,901	$143,512	$143,123	$1,723,370	$1,590,803	$132,567
25	Plant NPDES Permit Compliance Projects	$74,505	$73,065	$76,731	$80,713	$87,549	$98,284	$104,349	$104,080	$103,810	$103,541	$103,272	$103,003	$1,112,903	$1,027,295	$85,608
26	Air Quality Compliance Program	$10,360,838	$10,337,019	$10,321,735	$10,301,812	$10,282,438	$10,097,003	$10,148,596	$10,131,336	$10,116,208	$10,099,828	$10,080,363	$10,067,655	$122,344,829	$112,933,688	$9,411,141
27	General Water Quality	$21,334	$33,143	$33,486	$33,531	$33,647	$34,084	$34,673	$34,771	$34,827	$34,846	$47,563	$65,629	$441,535	$407,571	$33,964
28	Coal Combustion Residuals	$510,153	$521,795	$649,036	$567,508	$563,686	$639,561	$766,043	$831,459	$884,208	$971,229	$1,090,467	$1,165,515	$9,160,660	$8,455,994	$704,666
29	Steam Electric Effluent Limitations Guidelines	$55,493	$55,585	$55,536	$55,534	$56,251	$55,551	$56,011	$55,987	$55,963	$55,939	$55,916	$55,892	$669,659	$618,147	$51,512
30	316(B) Intake Structure Regulation	$2,109	$3,388	$5,163	$6,291	$6,859	$6,964	$7,188	$7,326	$9,387	$14,007	$20,684	$25,288	$114,654	$105,834	$8,820
31	Mercury Allowances	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Annual NOx Allowances	$31	$29	$30	$29	$29	$28	$28	$28	$27	$27	$26	$26	$336	$310	$26
33	Seasonal NOx Allowances	$17	$17	$17	$17	$17	$16	$14	$11	$9	$8	$256	$504	$904	$834	$70
34	SO2 Allowances	$36,329	$36,313	$36,309	$36,254	$36,200	$36,196	$36,640	$36,633	$36,626	$36,621	$36,619	$36,618	$437,357	$403,714	$33,643
35	Scherer/Flint Credit - Energy	($9,777)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9,777)	$0	($9,777)
35	Scherer/Flint Credit - Demand	($117,327)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($117,327)	($117,327)	$0
36	Regulatory Asset Smith Units 1 & 2	$224,899	$224,215	$223,531	$222,848	$222,164	$221,480	$222,073	$221,381	$220,688	$219,996	$219,304	$218,612	$2,661,190	$2,456,484	$204,707
2	Total Investment Programs - Recoverable Costs	$13,149,639	$13,268,924	$13,377,216	$13,272,527	$13,260,833	$13,160,541	$13,357,001	$13,401,344	$13,435,590	$13,505,191	$13,618,908	$13,698,484	$160,506,198	$148,159,568	$12,346,631
3	Recoverable Costs Allocated to Energy	$1,011,511	$1,020,686	$1,029,017	$1,020,964	$1,020,064	$1,012,349	$1,027,462	$1,030,873	$1,033,507	$1,038,861	$1,047,608	$1,053,730	$12,346,631		
4	Recoverable Costs Allocated to Demand	$12,138,128	$12,248,238	$12,348,200	$12,251,564	$12,240,769	$12,148,192	$12,329,539	$12,370,471	$12,402,083	$12,466,330	$12,571,299	$12,644,754	$148,159,568		
5	Retail Energy Jurisdictional Factor (B)	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 (C)	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427			
7	Jurisdictional Energy Recoverable Costs	$1,012,724	$1,021,911	$1,030,251	$1,022,189	$1,021,288	$1,013,564	$1,028,695	$1,032,110	$1,034,747	$1,040,107	$1,048,865	$1,054,994	$12,361,447		
8	Jurisdictional Demand Recoverable Costs	$11,802,420	$11,909,485	$12,006,682	$11,912,719	$11,902,223	$11,812,206	$11,988,538	$12,028,337	$12,059,075	$12,121,545	$12,223,611	$12,295,035	$144,061,874		
9	Total Jurisdictional Recoverable Costs for Investment Programs (Lines 7 + 8)	$12,815,145	$12,931,396	$13,036,933	$12,934,907	$12,923,511	$12,825,770	$13,017,232	$13,060,447	$13,093,822	$13,161,652	$13,272,477	$13,350,029	$156,423,321		

Notes:
(A) Each project's Total Recoverable Costs on Form 42-8E
(B) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(C) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Air Quality Assurance Testing

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	
3	Less: Accumulated Depreciation (C)	(3,998)	(4,997)	(5,997)	(6,996)	(7,996)	(8,995)	(9,995)	(10,994)	(11,993)	(12,993)	(13,992)	(14,992)	(15,991)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	79,956	78,957	77,957	76,958	75,958	74,959	73,959	72,960	71,960	70,961	69,962	68,962	67,963	
6	Average Net Investment		79,456	78,457	77,457	76,458	75,459	74,459	73,460	72,460	71,461	70,461	69,462	68,462	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		366	361	357	352	347	343	352	347	342	337	333	328	4,165
	b Debt Component (Line 6 x Debt Component x 1/12)		92	91	90	89	88	87	77	76	75	74	73	72	983
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		999	999	999	999	999	999	999	999	999	999	999	999	11,993
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,458	1,452	1,446	1,440	1,435	1,429	1,428	1,422	1,417	1,411	1,405	1,399	17,141
	a Recoverable Costs Allocated to Energy		112	112	111	111	110	110	110	109	109	109	108	108	1,319
	b Recoverable Costs Allocated to Demand		1,345	1,340	1,335	1,330	1,324	1,319	1,318	1,313	1,308	1,302	1,297	1,292	15,823
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		112	112	111	111	110	110	110	110	109	109	108	108	1,320
13	Retail Demand-Related Recoverable Costs (I)		1,308	1,303	1,298	1,293	1,288	1,282	1,282	1,277	1,272	1,266	1,261	1,256	15,385
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,421	1,415	1,409	1,404	1,398	1,392	1,392	1,386	1,381	1,375	1,369	1,364	16,705

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist 5, 6 & 7 Precipitator Programs

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	
3	Less: Accumulated Depreciation (C)	1,086,225	974,034	861,844	749,654	637,464	525,273	413,083	300,893	188,702	76,512	(35,678)	(147,868)	(260,059)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	34,743,311	34,631,121	34,518,931	34,406,741	34,294,550	34,182,360	34,070,170	33,957,979	33,845,789	33,733,599	33,621,409	33,509,218	33,397,028	
6	Average Net Investment		34,687,216	34,575,026	34,462,836	34,350,645	34,238,455	34,126,265	34,014,075	33,901,884	33,789,694	33,677,504	33,565,313	33,453,123	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		159,700	159,183	158,667	158,150	157,634	157,117	162,893	162,356	161,819	161,282	160,744	160,207	1,919,753
	b Debt Component (Line 6 x Debt Component x 1/12)		40,307	40,176	40,046	39,915	39,785	39,655	35,681	35,563	35,445	35,328	35,210	35,092	452,203
8	Investment Expenses														
	a Depreciation (E)		112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	1,346,283
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		312,197	311,550	310,903	310,256	309,609	308,962	310,764	310,109	309,455	308,800	308,145	307,490	3,718,240
	a Recoverable Costs Allocated to Energy		24,015	23,965	23,916	23,866	23,816	23,766	23,905	23,855	23,804	23,754	23,703	23,653	286,018
	b Recoverable Costs Allocated to Demand		288,182	287,585	286,987	286,390	285,793	285,196	286,859	286,255	285,650	285,046	284,441	283,837	3,432,221
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		24,044	23,994	23,944	23,894	23,845	23,795	23,934	23,883	23,833	23,782	23,732	23,681	286,362
13	Retail Demand-Related Recoverable Costs (I)		280,211	279,631	279,050	278,469	277,889	277,308	278,926	278,338	277,750	277,162	276,574	275,986	3,337,295
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		304,255	303,625	302,994	302,364	301,734	301,103	302,859	302,221	301,583	300,944	300,306	299,668	3,623,657

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist 7 Flue Gas Conditioning

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
6	Average Net Investment		1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,903	6,903	6,903	6,903	6,903	6,903	7,180	7,180	7,180	7,180	7,180	7,180	84,499
	b Debt Component (Line 6 x Debt Component x 1/12)		1,742	1,742	1,742	1,742	1,742	1,742	1,573	1,573	1,573	1,573	1,573	1,573	19,890
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,645	8,645	8,645	8,645	8,645	8,645	8,753	8,753	8,753	8,753	8,753	8,753	104,389
	a Recoverable Costs Allocated to Energy		665	665	665	665	665	665	673	673	673	673	673	673	8,030
	b Recoverable Costs Allocated to Demand		7,980	7,980	7,980	7,980	7,980	7,980	8,080	8,080	8,080	8,080	8,080	8,080	96,359
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		666	666	666	666	666	666	674	674	674	674	674	674	8,040
13	Retail Demand-Related Recoverable Costs (I)		7,759	7,759	7,759	7,759	7,759	7,759	7,856	7,856	7,856	7,856	7,856	7,856	93,694
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,425	8,425	8,425	8,425	8,425	8,425	8,530	8,530	8,530	8,530	8,530	8,530	101,733

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Low NOx Burners, Crist 6 & 7

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	
3	Less: Accumulated Depreciation (C)	3,671,263	3,624,938	3,578,612	3,532,287	3,485,962	3,439,636	3,393,311	3,346,986	3,300,660	3,254,335	3,208,010	3,161,684	3,115,359	
4	CWIP - Non Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4) (A)	17,199,195	17,152,869	17,106,544	17,060,219	17,013,893	16,967,568	16,921,243	16,874,917	16,828,592	16,782,267	16,735,941	16,689,616	16,643,291	
6	Average Net Investment		17,176,032	17,129,707	17,083,381	17,037,056	16,990,731	16,944,405	16,898,080	16,851,755	16,805,429	16,759,104	16,712,779	16,666,453	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		79,078	78,865	78,652	78,439	78,225	78,012	80,925	80,703	80,481	80,259	80,037	79,816	953,493
	b Debt Component (Line 6 x Debt Component x 1/12)		19,959	19,905	19,851	19,797	19,743	19,689	17,726	17,677	17,629	17,580	17,532	17,483	224,571
8	Investment Expenses														
	a Depreciation (E)		44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	535,367
	b Amortization (F)		1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	20,537
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		145,362	145,095	144,828	144,561	144,294	144,027	144,976	144,706	144,435	144,165	143,895	143,624	1,733,968
	a Recoverable Costs Allocated to Energy		11,182	11,161	11,141	11,120	11,100	11,079	11,152	11,131	11,110	11,090	11,069	11,048	133,382
	b Recoverable Costs Allocated to Demand		134,181	133,934	133,687	133,441	133,194	132,948	133,824	133,575	133,325	133,075	132,826	132,576	1,600,586
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		11,195	11,175	11,154	11,133	11,113	11,092	11,165	11,145	11,124	11,103	11,082	11,061	133,542
13	Retail Demand-Related Recoverable Costs (I)		130,470	130,230	129,990	129,750	129,511	129,271	130,123	129,880	129,638	129,395	129,152	128,909	1,556,318
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		141,665	141,404	141,144	140,884	140,623	140,363	141,288	141,025	140,761	140,498	140,234	139,971	1,689,861

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: CEMS - Plants Crist & Daniel

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		(29)	0	0	0	0	0	0	0	0	0	0	0	(29)
2	Plant-in-Service/Depreciation Base (B)	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	
3	Less: Accumulated Depreciation (C)	266,590	251,344	236,127	220,911	205,694	190,477	175,261	160,044	144,828	129,611	114,394	99,178	83,961	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	4,979,373	4,964,127	4,948,910	4,933,694	4,918,477	4,903,260	4,888,044	4,872,827	4,857,611	4,842,394	4,827,177	4,811,961	4,796,744	
6	Average Net Investment		4,971,750	4,956,519	4,941,302	4,926,085	4,910,869	4,895,652	4,880,435	4,865,219	4,850,002	4,834,786	4,819,569	4,804,352	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		22,890	22,820	22,750	22,680	22,610	22,540	23,372	23,300	23,227	23,154	23,081	23,008	275,430
	b Debt Component (Line 6 x Debt Component x 1/12)		5,777	5,759	5,742	5,724	5,706	5,689	5,120	5,104	5,088	5,072	5,056	5,040	64,876
8	Investment Expenses														
	a Depreciation (E)		15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	182,599
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		872	872	872	872	872	872	872	872	872	872	872	872	10,460
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		44,755	44,668	44,580	44,492	44,404	44,317	44,580	44,491	44,403	44,314	44,225	44,136	533,364
	a Recoverable Costs Allocated to Energy		3,443	3,436	3,429	3,422	3,416	3,409	3,429	3,422	3,416	3,409	3,402	3,395	41,028
	b Recoverable Costs Allocated to Demand		41,313	41,232	41,151	41,070	40,989	40,908	41,151	41,069	40,987	40,905	40,823	40,741	492,336
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		3,447	3,440	3,433	3,427	3,420	3,413	3,433	3,427	3,420	3,413	3,406	3,399	41,077
13	Retail Demand-Related Recoverable Costs (I)		40,170	40,091	40,012	39,934	39,855	39,776	40,013	39,933	39,853	39,774	39,694	39,614	478,720
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		43,617	43,531	43,446	43,360	43,275	43,189	43,446	43,360	43,273	43,186	43,100	43,013	519,797

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Substation Contamination Remediation

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		11,588	27,124	(25,982)	(554,252)	3,630	103,500	1,036,252	18,000	6,250	6,250	16,750	1,250	650,360
	b Clearings to Plant		0	0	0	(554,252)	0	0	1,031,252	0	0	0	0	0	477,000
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	554,252	0	0	(554,252)	0	0	0	0	0	0
	e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		588	0	0	0	0	0	0	0	0	0	0	0	588
2	Plant-in-Service/Depreciation Base (B)	3,245,823	3,245,823	3,245,823	3,245,823	2,691,572	2,691,572	2,691,572	3,722,823	3,722,823	3,722,823	3,722,823	3,722,823	3,722,823	
3	Less: Accumulated Depreciation (C)	1,058,872	1,052,058	1,044,657	1,037,255	1,584,821	1,578,851	1,572,881	1,012,659	1,006,690	1,000,720	994,750	988,780	982,810	
4	CWIP - Non Interest Bearing	294,900	306,488	333,612	307,630	307,630	311,260	414,760	419,760	437,760	444,010	450,260	467,010	468,260	
5	Net Investment (Lines 2 + 3 + 4) (A)	4,599,596	4,604,369	4,624,092	4,590,708	4,584,022	4,581,682	4,679,212	5,155,242	5,167,272	5,167,553	5,167,833	5,178,613	5,173,893	
6	Average Net Investment		4,601,982	4,614,231	4,607,400	4,587,365	4,582,852	4,630,447	4,917,227	5,161,257	5,167,412	5,167,693	5,173,223	5,176,253	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		21,188	21,244	21,212	21,120	21,099	21,319	23,549	24,717	24,747	24,748	24,775	24,789	274,506
	b Debt Component (Line 6 x Debt Component x 1/12)		5,348	5,362	5,354	5,331	5,325	5,381	5,158	5,414	5,421	5,421	5,427	5,430	64,370
8	Investment Expenses														
	a Depreciation (E)		7,402	7,402	7,402	6,686	5,970	5,970	5,970	5,970	5,970	5,970	5,970	5,970	76,650
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		33,937	34,007	33,968	33,137	32,395	32,669	34,677	36,101	36,137	36,139	36,171	36,189	415,526
	a Recoverable Costs Allocated to Energy		2,611	2,616	2,613	2,549	2,492	2,513	2,667	2,777	2,780	2,780	2,782	2,784	31,964
	b Recoverable Costs Allocated to Demand		31,326	31,391	31,355	30,588	29,903	30,156	32,009	33,324	33,357	33,359	33,389	33,405	383,563
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		2,614	2,619	2,616	2,552	2,495	2,516	2,671	2,780	2,783	2,783	2,786	2,787	32,002
13	Retail Demand-Related Recoverable Costs (I)		30,460	30,523	30,488	29,742	29,076	29,322	31,124	32,403	32,435	32,436	32,465	32,481	372,955
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		33,073	33,142	33,104	32,294	31,571	31,838	33,795	35,183	35,218	35,220	35,251	35,268	404,956

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020

For Program: Raw Water Well Flowmeters - Plants Crist & Smith

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	
3	Less: Accumulated Depreciation (C)	(50,859)	(51,359)	(51,859)	(52,359)	(52,859)	(53,358)	(53,858)	(54,358)	(54,858)	(55,358)	(55,858)	(56,357)	(56,857)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	99,090	98,591	98,091	97,591	97,091	96,591	96,091	95,592	95,092	94,592	94,092	93,592	93,092	
6	Average Net Investment		98,840	98,341	97,841	97,341	96,841	96,341	95,841	95,342	94,842	94,342	93,842	93,342	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		455	453	450	448	446	444	459	457	454	452	449	447	5,414
	b Debt Component (Line 6 x Debt Component x 1/12)		115	114	114	113	113	112	101	100	99	99	98	98	1,276
8	Investment Expenses														
	a Depreciation (E)		500	500	500	500	500	500	500	500	500	500	500	500	5,998
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,070	1,067	1,064	1,061	1,058	1,055	1,059	1,056	1,054	1,051	1,048	1,045	12,688
	a Recoverable Costs Allocated to Energy		82	82	82	82	81	81	81	81	81	81	81	80	976
	b Recoverable Costs Allocated to Demand		987	985	982	979	977	974	978	975	972	970	967	964	11,712
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		82	82	82	82	81	81	82	81	81	81	81	80	977
13	Retail Demand-Related Recoverable Costs (I)		960	958	955	952	950	947	951	948	946	943	940	938	11,388
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,043	1,040	1,037	1,034	1,031	1,028	1,032	1,030	1,027	1,024	1,021	1,018	12,365

Notes:

(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist Cooling Tower Cell

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
6	Average Net Investment		531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,449	2,449	2,449	2,449	2,449	2,449	2,547	2,547	2,547	2,547	2,547	2,547	29,978
	b Debt Component (Line 6 x Debt Component x 1/12)		618	618	618	618	618	618	558	558	558	558	558	558	7,057
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,067	3,067	3,067	3,067	3,067	3,067	3,105	3,105	3,105	3,105	3,105	3,105	37,035
	a Recoverable Costs Allocated to Energy		236	236	236	236	236	236	239	239	239	239	239	239	2,849
	b Recoverable Costs Allocated to Demand		2,831	2,831	2,831	2,831	2,831	2,831	2,867	2,867	2,867	2,867	2,867	2,867	34,186
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		236	236	236	236	236	236	239	239	239	239	239	239	2,852
13	Retail Demand-Related Recoverable Costs (I)		2,753	2,753	2,753	2,753	2,753	2,753	2,787	2,787	2,787	2,787	2,787	2,787	33,241
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,989	2,989	2,989	2,989	2,989	2,989	3,026	3,026	3,026	3,026	3,026	3,026	36,093

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist Dechlorination System

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	
3	Less: Accumulated Depreciation (C)	(258,869)	(260,138)	(261,407)	(262,676)	(263,945)	(265,214)	(266,483)	(267,752)	(269,021)	(270,290)	(271,559)	(272,828)	(274,097)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	121,828	120,559	119,290	118,021	116,752	115,483	114,214	112,945	111,676	110,407	109,138	107,869	106,600	
6	Average Net Investment		121,194	119,925	118,656	117,387	116,118	114,849	113,580	112,311	111,042	109,773	108,504	107,235	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		558	552	546	540	535	529	544	538	532	526	520	514	6,433
	b Debt Component (Line 6 x Debt Component x 1/12)		141	139	138	136	135	133	119	118	116	115	114	112	1,518
8	Investment Expenses														
	a Depreciation (E)		1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	15,228
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,968	1,960	1,953	1,946	1,939	1,931	1,932	1,925	1,917	1,910	1,902	1,895	23,178
	a Recoverable Costs Allocated to Energy		151	151	150	150	149	149	149	148	147	147	146	146	1,783
	b Recoverable Costs Allocated to Demand		1,816	1,810	1,803	1,796	1,789	1,783	1,783	1,777	1,770	1,763	1,756	1,749	21,395
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		152	151	150	150	149	149	149	148	148	147	147	146	1,785
13	Retail Demand-Related Recoverable Costs (I)		1,766	1,760	1,753	1,746	1,740	1,733	1,734	1,727	1,721	1,714	1,708	1,701	20,804
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,918	1,911	1,903	1,896	1,889	1,882	1,883	1,876	1,868	1,861	1,854	1,847	22,589

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist Diesel Fuel Oil Remediation

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		0	0	0	0	36,282	0	0	0	0	0	0	0	36,282
2	Plant-in-Service/Depreciation Base (B)	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	
3	Less: Accumulated Depreciation (C)	(52,562)	(52,632)	(52,702)	(52,772)	(52,842)	(16,630)	(16,700)	(16,769)	(16,839)	(16,909)	(16,979)	(17,049)	(17,119)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	(31,595)	(31,665)	(31,734)	(31,804)	(31,874)	4,338	4,268	4,198	4,128	4,058	3,988	3,919	3,849	
6	Average Net Investment		(31,630)	(31,699)	(31,769)	(31,839)	(13,768)	4,303	4,233	4,163	4,093	4,023	3,954	3,884	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		(146)	(146)	(146)	(147)	(63)	20	20	20	20	19	19	19	(511)
	b Debt Component (Line 6 x Debt Component x 1/12)		(37)	(37)	(37)	(37)	(16)	5	4	4	4	4	4	4	(133)
8	Investment Expenses														
	a Depreciation (E)		70	70	70	70	70	70	70	70	70	70	70	70	839
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		(112)	(113)	(113)	(114)	(9)	95	95	94	94	93	93	93	194
	a Recoverable Costs Allocated to Energy		(9)	(9)	(9)	(9)	(1)	7	7	7	7	7	7	7	15
	b Recoverable Costs Allocated to Demand		(104)	(104)	(105)	(105)	(9)	87	87	87	87	86	86	85	179
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		(9)	(9)	(9)	(9)	(1)	7	7	7	7	7	7	7	15
13	Retail Demand-Related Recoverable Costs (I)		(101)	(101)	(102)	(102)	(9)	85	85	85	84	84	83	83	174
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		(110)	(110)	(110)	(111)	(9)	92	92	92	91	91	91	90	189

Notes:
(A) Prior period adjustment to reserve balance made in May 2020.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist Bulk Tanker Unloading Secondary Containment

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(88,134)	(88,473)	(88,811)	(89,149)	(89,488)	(89,826)	(90,164)	(90,503)	(90,841)	(91,179)	(91,518)	(91,856)	(92,194)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	13,361	13,022	12,684	12,346	12,007	11,669	11,331	10,992	10,654	10,316	9,977	9,639	9,301	
6	Average Net Investment		13,191	12,853	12,515	12,176	11,838	11,500	11,162	10,823	10,485	10,147	9,808	9,470	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		61	59	58	56	55	53	53	52	50	49	47	45	637
	b Debt Component (Line 6 x Debt Component x 1/12)		15	15	15	14	14	13	12	11	11	11	10	10	151
8	Investment Expenses														
	a Depreciation (E)		338	338	338	338	338	338	338	338	338	338	338	338	4,060
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		414	412	410	409	407	405	403	402	400	398	396	394	4,848
	a Recoverable Costs Allocated to Energy		32	32	32	31	31	31	31	31	31	31	30	30	373
	b Recoverable Costs Allocated to Demand		383	381	379	377	375	374	372	371	369	367	365	363	4,475
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		32	32	32	31	31	31	31	31	31	31	30	30	373
13	Retail Demand-Related Recoverable Costs (I)		372	370	368	367	365	363	362	360	359	357	355	353	4,352
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		404	402	400	398	396	394	393	391	389	387	386	384	4,725

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist IWW Sampling System

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(52,023)	(52,222)	(52,420)	(52,619)	(52,817)	(53,015)	(53,214)	(53,412)	(53,611)	(53,809)	(54,008)	(54,206)	(54,405)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	7,520	7,321	7,123	6,924	6,726	6,527	6,329	6,130	5,932	5,733	5,535	5,336	5,138	
6	Average Net Investment		7,420	7,222	7,023	6,825	6,627	6,428	6,230	6,031	5,833	5,634	5,436	5,237	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		34	33	32	31	31	30	30	29	28	27	26	25	356
	b Debt Component (Line 6 x Debt Component x 1/12)		9	8	8	8	8	7	7	6	6	6	6	5	84
8	Investment Expenses														
	a Depreciation (E)		198	198	198	198	198	198	198	198	198	198	198	198	2,382
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		241	240	239	238	237	236	235	234	233	231	230	229	2,822
	a Recoverable Costs Allocated to Energy		19	18	18	18	18	18	18	18	18	18	18	18	217
	b Recoverable Costs Allocated to Demand		223	222	221	220	218	217	217	216	215	214	213	211	2,605
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		19	18	18	18	18	18	18	18	18	18	18	18	217
13	Retail Demand-Related Recoverable Costs (I)		217	216	214	213	212	211	211	210	209	208	207	206	2,533
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		235	234	233	232	231	230	229	228	227	225	224	223	2,750

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Sodium Injection System

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	
3	Less: Accumulated Depreciation (C)	(140,871)	(141,819)	(142,768)	(143,717)	(144,666)	(145,614)	(146,563)	(147,512)	(148,460)	(149,409)	(150,358)	(151,307)	(152,255)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	143,751	142,802	141,854	140,905	139,956	139,007	138,059	137,110	136,161	135,213	134,264	133,315	132,366	
6	Average Net Investment		143,277	142,328	141,379	140,431	139,482	138,533	137,584	136,636	135,687	134,738	133,789	132,841	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		660	655	651	647	642	638	659	654	650	645	641	636	7,778
	b Debt Component (Line 6 x Debt Component x 1/12)		166	165	164	163	162	161	144	143	142	141	140	139	1,833
8	Investment Expenses														
	a Depreciation (E)		949	949	949	949	949	949	949	949	949	949	949	949	11,385
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,775	1,769	1,764	1,758	1,753	1,748	1,752	1,746	1,741	1,735	1,730	1,724	20,996
	a Recoverable Costs Allocated to Energy		137	136	136	135	135	134	135	134	134	133	133	133	1,615
	b Recoverable Costs Allocated to Demand		1,638	1,633	1,628	1,623	1,618	1,613	1,617	1,612	1,607	1,602	1,597	1,592	19,381
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		137	136	136	135	135	135	135	135	134	134	133	133	1,617
13	Retail Demand-Related Recoverable Costs (I)		1,593	1,588	1,583	1,578	1,573	1,568	1,572	1,567	1,563	1,558	1,553	1,548	18,845
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,730	1,724	1,719	1,714	1,708	1,703	1,707	1,702	1,697	1,691	1,686	1,680	20,462

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Smith Stormwater Collection System

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	
3	Less: Accumulated Depreciation (C)	(2,186,795)	(2,197,622)	(2,208,449)	(2,219,277)	(2,230,104)	(2,240,931)	(2,251,758)	(2,262,585)	(2,273,412)	(2,284,240)	(2,295,067)	(2,305,894)	(2,316,721)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	577,583	566,756	555,929	545,102	534,275	523,448	512,621	501,793	490,966	480,139	469,312	458,485	447,658	
6	Average Net Investment		572,170	561,343	550,516	539,688	528,861	518,034	507,207	496,380	485,553	474,726	463,898	453,071	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,634	2,584	2,535	2,485	2,435	2,385	2,429	2,377	2,325	2,273	2,222	2,170	28,854
	b Debt Component (Line 6 x Debt Component x 1/12)		665	652	640	627	615	602	532	521	509	498	487	475	6,822
8	Investment Expenses														
	a Depreciation (E)		10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	129,926
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		14,126	14,064	14,001	13,939	13,877	13,814	13,788	13,725	13,662	13,599	13,535	13,472	165,602
	a Recoverable Costs Allocated to Energy		1,087	1,082	1,077	1,072	1,067	1,063	1,061	1,056	1,051	1,046	1,041	1,036	12,739
	b Recoverable Costs Allocated to Demand		13,040	12,982	12,924	12,867	12,809	12,752	12,728	12,669	12,611	12,553	12,494	12,436	152,864
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		1,088	1,083	1,078	1,074	1,069	1,064	1,062	1,057	1,052	1,047	1,042	1,038	12,754
13	Retail Demand-Related Recoverable Costs (I)		12,679	12,623	12,567	12,511	12,455	12,399	12,376	12,319	12,262	12,205	12,149	12,092	148,636
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		13,767	13,706	13,645	13,584	13,524	13,463	13,437	13,376	13,314	13,253	13,191	13,129	161,390

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Smith Waste Water Treatment Facility

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	464,658	0	0	0	0	0	0	0	0	0	0	464,658
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		(7,018)	13,505	9,030	7,069	0	0	0	0	0	0	0	0	22,586
	e PIS Adjustment		0	(464,658)	0	0	464,658	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		4,596	0	0	0	(3,553)	0	0	0	0	0	0	0	1,043
2	Plant-in-Service/Depreciation Base (B)	178,962	178,962	178,962	178,962	178,962	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	
3	Less: Accumulated Depreciation (C)	128,007	124,884	137,688	146,017	152,385	146,311	143,790	141,269	138,748	136,228	133,707	131,186	128,665	
4	CWIP - Non Interest Bearing	464,658	464,658	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	771,626	768,503	316,650	324,978	331,347	789,930	787,410	784,889	782,368	779,847	777,326	774,805	772,285	
6	Average Net Investment		770,065	542,576	320,814	328,163	560,639	788,670	786,149	783,628	781,108	778,587	776,066	773,545	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,545	2,498	1,477	1,511	2,581	3,631	3,765	3,753	3,741	3,729	3,717	3,705	37,652
	b Debt Component (Line 6 x Debt Component x 1/12)		895	630	373	381	651	916	825	822	819	817	814	811	8,756
8	Investment Expenses														
	a Depreciation (E)		701	701	701	701	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	22,970
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,141	3,829	2,551	2,593	5,753	7,068	7,110	7,096	7,081	7,066	7,052	7,037	69,378
	a Recoverable Costs Allocated to Energy		395	295	196	199	443	544	547	546	545	544	542	541	5,337
	b Recoverable Costs Allocated to Demand		4,746	3,535	2,355	2,394	5,311	6,525	6,563	6,550	6,536	6,523	6,509	6,496	64,041
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		396	295	196	200	443	544	548	546	545	544	543	542	5,343
13	Retail Demand-Related Recoverable Costs (I)		4,614	3,437	2,289	2,327	5,164	6,344	6,382	6,369	6,355	6,342	6,329	6,316	62,270
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		5,010	3,732	2,486	2,527	5,607	6,889	6,930	6,915	6,901	6,886	6,872	6,858	67,613

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs. Timing of CWIP transfers, under the new automated data environment, creates the need for catchup adjustments until fully implemented.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Daniel Ash Management Program

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		(6)	0	0	0	0	0	0	0	0	0	0	0	(6)
2	Plant-in-Service/Depreciation Base (B)	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	
3	Less: Accumulated Depreciation (C)	(6,833,021)	(6,870,382)	(6,907,737)	(6,945,092)	(6,982,446)	(7,019,801)	(7,057,156)	(7,094,511)	(7,131,866)	(7,169,221)	(7,206,576)	(7,243,931)	(7,281,286)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	8,106,540	8,069,179	8,031,824	7,994,470	7,957,115	7,919,760	7,882,405	7,845,050	7,807,695	7,770,340	7,732,985	7,695,630	7,658,275	
6	Average Net Investment		8,087,860	8,050,502	8,013,147	7,975,792	7,938,437	7,901,082	7,863,727	7,826,372	7,789,017	7,751,663	7,714,308	7,676,953	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		37,237	37,065	36,893	36,721	36,549	36,377	37,659	37,480	37,302	37,123	36,944	36,765	444,112
	b Debt Component (Line 6 x Debt Component x 1/12)		9,398	9,355	9,311	9,268	9,224	9,181	8,249	8,210	8,171	8,131	8,092	8,053	104,644
8	Investment Expenses														
	a Depreciation (E)		37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	448,259
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	246,481
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		104,530	104,314	104,099	103,883	103,668	103,453	103,803	103,585	103,367	103,149	102,931	102,713	1,243,496
	a Recoverable Costs Allocated to Energy		8,041	8,024	8,008	7,991	7,974	7,958	7,985	7,968	7,951	7,935	7,918	7,901	95,654
	b Recoverable Costs Allocated to Demand		96,489	96,290	96,091	95,892	95,694	95,495	95,819	95,617	95,416	95,215	95,013	94,812	1,147,843
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		8,050	8,034	8,017	8,001	7,984	7,967	7,994	7,978	7,961	7,944	7,927	7,910	95,768
13	Retail Demand-Related Recoverable Costs (I)		93,820	93,627	93,434	93,240	93,047	92,854	93,168	92,973	92,777	92,581	92,386	92,190	1,116,097
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		101,871	101,661	101,451	101,241	101,031	100,821	101,163	100,950	100,738	100,525	100,313	100,100	1,211,865

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Smith Water Conservation

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		(5,523)	4,464	5,916	1,049	16,483	22,385	59,015	77,330	40,700	22,894	22,894	33,069	300,675
	b Clearings to Plant		0	6,087	214,648	351,783	0	0	0	0	0	0	0	0	572,518
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e PIS Adjustment		0	0	(214,648)	(346,443)	561,092	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		(753)	0	0	0	(4,290)	0	0	0	0	0	0	0	(5,044)
2	Plant-in-Service/Depreciation Base (B)	21,018,243	21,018,243	21,024,330	21,024,330	21,029,670	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	
3	Less: Accumulated Depreciation (C)	(2,473,936)	(2,557,010)	(2,639,344)	(2,721,689)	(2,804,045)	(2,892,899)	(2,977,463)	(3,062,027)	(3,146,590)	(3,231,154)	(3,315,718)	(3,400,282)	(3,484,846)	
4	CWIP - Non Interest Bearing	574,610	569,087	567,464	358,732	7,998	24,481	46,866	105,881	183,211	223,911	246,805	269,699	302,767	
5	Net Investment (Lines 2 + 3 + 4) (A)	19,118,917	19,030,320	18,952,450	18,661,372	18,233,623	18,722,343	18,660,165	18,634,616	18,627,382	18,583,518	18,521,848	18,460,178	18,408,683	
6	Average Net Investment		19,074,619	18,991,385	18,806,911	18,447,497	18,477,983	18,691,254	18,647,390	18,630,999	18,605,450	18,552,683	18,491,013	18,434,430	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		87,820	87,436	86,587	84,932	85,073	86,055	89,302	89,224	89,102	88,849	88,553	88,282	1,051,215
	b Debt Component (Line 6 x Debt Component x 1/12)		22,165	22,068	21,854	21,436	21,471	21,719	19,561	19,544	19,517	19,462	19,397	19,338	247,532
8	Investment Expenses														
	a Depreciation (E)		82,321	82,333	82,345	82,356	84,564	84,564	84,564	84,564	84,564	84,564	84,564	84,564	1,005,866
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		192,306	191,838	190,786	188,724	191,108	192,338	193,427	193,332	193,182	192,874	192,514	192,184	2,304,613
	a Recoverable Costs Allocated to Energy		14,793	14,757	14,676	14,517	14,701	14,795	14,879	14,872	14,860	14,836	14,809	14,783	177,278
	b Recoverable Costs Allocated to Demand		177,513	177,081	176,110	174,207	176,407	177,542	178,548	178,460	178,322	178,038	177,706	177,401	2,127,335
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		14,810	14,774	14,693	14,535	14,718	14,813	14,897	14,890	14,878	14,854	14,827	14,801	177,491
13	Retail Demand-Related Recoverable Costs (I)		172,603	172,183	171,239	169,389	171,528	172,632	173,610	173,524	173,390	173,114	172,791	172,494	2,068,499
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		187,414	186,958	185,933	183,923	186,247	187,445	188,507	188,414	188,268	187,968	187,617	187,295	2,245,989

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs. Timing of CWIP transfers, under the new automated data environment, creates the need for catchup adjustments until fully implemented.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Underground Fuel Tank Replacement

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist FDEP Agreement for Ozone Attainment

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		3,625	0	0	0	0	0	0	0	0	0	0	0	3,625
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		2,175	0	0	0	0	0	0	0	0	0	0	0	2,175
	e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		297,647	0	0	0	0	(297,645)	0	0	0	0	0	0	2
2	Plant-in-Service/Depreciation Base (B)	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	
3	Less: Accumulated Depreciation (C)	(38,453,274)	(38,559,142)	(38,964,832)	(39,370,522)	(39,776,212)	(40,181,902)	(40,885,237)	(41,290,927)	(41,696,616)	(42,102,306)	(42,507,996)	(42,913,686)	(43,319,375)	
4	CWIP - Non Interest Bearing	443,813	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	
5	Net Investment (Lines 2 + 3 + 4) (A)	81,574,458	81,472,215	81,066,525	80,660,835	80,255,145	79,849,455	79,146,120	78,740,430	78,334,741	77,929,051	77,523,361	77,117,671	76,711,982	
6	Average Net Investment		81,523,337	81,269,370	80,863,680	80,457,990	80,052,300	79,497,788	78,943,275	78,537,585	78,131,896	77,726,206	77,320,516	76,914,826	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		375,333	374,164	372,296	370,429	368,561	366,008	378,059	376,116	374,174	372,231	370,288	368,345	4,466,005
	b Debt Component (Line 6 x Debt Component x 1/12)		94,730	94,435	93,964	93,492	93,021	92,376	82,811	82,386	81,960	81,535	81,109	80,684	1,052,504
8	Investment Expenses														
	a Depreciation (E)		395,364	395,364	395,364	395,364	395,363	395,363	395,363	395,363	395,363	395,363	395,363	395,363	4,744,361
	b Amortization (F)		10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	123,917
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		875,754	874,289	871,950	869,611	867,271	864,074	866,561	864,192	861,824	859,455	857,087	854,718	10,386,786
	a Recoverable Costs Allocated to Energy		67,366	67,253	67,073	66,893	66,713	66,467	66,659	66,476	66,294	66,112	65,930	65,748	798,984
	b Recoverable Costs Allocated to Demand		808,388	807,036	804,877	802,718	800,558	797,607	799,902	797,716	795,530	793,343	791,157	788,971	9,587,803
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		67,446	67,334	67,154	66,973	66,793	66,547	66,738	66,556	66,374	66,191	66,009	65,826	799,942
13	Retail Demand-Related Recoverable Costs (I)		786,030	784,716	782,616	780,517	778,417	775,547	777,779	775,653	773,527	771,402	769,276	767,150	9,322,630
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		853,477	852,050	849,770	847,490	845,210	842,094	844,517	842,209	839,901	837,593	835,285	832,977	10,122,572

Notes:
(A) Adjustment to reserve balance in January and June 2020.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: SPCC Compliance

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	947,925	
3	Less: Accumulated Depreciation (C)	(430,582)	(433,863)	(437,145)	(440,426)	(443,708)	(446,990)	(450,271)	(453,553)	(456,834)	(460,116)	(463,397)	(466,679)	(469,960)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	517,343	514,061	510,780	507,498	504,217	500,935	497,654	494,372	491,091	487,809	484,528	481,246	477,965	
6	Average Net Investment		515,702	512,421	509,139	505,858	502,576	499,295	496,013	492,731	489,450	486,168	482,887	479,605	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,374	2,359	2,344	2,329	2,314	2,299	2,375	2,360	2,344	2,328	2,313	2,297	28,036
	b Debt Component (Line 6 x Debt Component x 1/12)		599	595	592	588	584	580	520	517	513	510	507	503	6,609
8	Investment Expenses														
	a Depreciation (E)		3,124	3,124	3,124	3,124	3,124	3,124	3,124	3,124	3,124	3,124	3,124	3,124	37,493
	b Amortization (F)		157	157	157	157	157	157	157	157	157	157	157	157	1,885
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		6,255	6,236	6,217	6,198	6,179	6,160	6,177	6,158	6,139	6,120	6,101	6,081	74,023
	a Recoverable Costs Allocated to Energy		481	480	478	477	475	474	475	474	472	471	469	468	5,694
	b Recoverable Costs Allocated to Demand		5,774	5,756	5,739	5,722	5,704	5,687	5,702	5,684	5,667	5,649	5,631	5,614	68,329
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		482	480	479	477	476	474	476	474	473	471	470	468	5,701
13	Retail Demand-Related Recoverable Costs (I)		5,614	5,597	5,580	5,563	5,546	5,529	5,544	5,527	5,510	5,493	5,476	5,458	66,439
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,096	6,078	6,059	6,041	6,022	6,004	6,020	6,001	5,983	5,964	5,945	5,927	72,140

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist Common FTIR Monitor

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e PIS Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		0	0	0	0	33,156	0	0	0	0	0	0	0	33,156
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	(33,155)	(33,155)	(33,155)	(33,155)	(33,155)	0	0	0	0	0	0	0	0	
6	Average Net Investment		(33,155)	(33,155)	(33,155)	(33,155)	(16,578)	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		(153)	(153)	(153)	(153)	(76)	0	0	0	0	0	0	0	(687)
	b Debt Component (Line 6 x Debt Component x 1/12)		(39)	(39)	(39)	(39)	(19)	0	0	0	0	0	0	0	(173)
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		(191)	(191)	(191)	(191)	(96)	0	0	0	0	0	0	0	(860)
	a Recoverable Costs Allocated to Energy		(15)	(15)	(15)	(15)	(7)	0	0	0	0	0	0	0	(66)
	b Recoverable Costs Allocated to Demand		(176)	(176)	(176)	(176)	(88)	0	0	0	0	0	0	0	(794)
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		(15)	(15)	(15)	(15)	(7)	0	0	0	0	0	0	0	(66)
13	Retail Demand-Related Recoverable Costs (I)		(172)	(172)	(172)	(172)	(86)	0	0	0	0	0	0	0	(772)
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		(186)	(186)	(186)	(186)	(93)	0	0	0	0	0	0	0	(838)

Notes:
(A) Prior period adjustment to reserve balance made in May 2020.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Precipitator Upgrades for CAM Compliance

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	
3	Less: Accumulated Depreciation (C)	(5,822,857)	(5,869,176)	(5,915,495)	(5,961,813)	(6,008,132)	(6,054,451)	(6,100,770)	(6,147,089)	(6,193,407)	(6,239,726)	(6,286,045)	(6,332,364)	(6,378,683)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	8,072,782	8,026,463	7,980,144	7,933,825	7,887,506	7,841,188	7,794,869	7,748,550	7,702,231	7,655,912	7,609,594	7,563,275	7,516,956	
6	Average Net Investment		8,049,622	8,003,303	7,956,985	7,910,666	7,864,347	7,818,028	7,771,709	7,725,391	7,679,072	7,632,753	7,586,434	7,540,115	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		37,060	36,847	36,634	36,421	36,207	35,994	37,219	36,997	36,775	36,553	36,331	36,110	439,149
	b Debt Component (Line 6 x Debt Component x 1/12)		9,354	9,300	9,246	9,192	9,138	9,085	8,153	8,104	8,055	8,007	7,958	7,910	103,501
8	Investment Expenses														
	a Depreciation (E)		46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	555,826
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		92,733	92,466	92,199	91,932	91,665	91,398	91,690	91,420	91,149	90,879	90,608	90,338	1,098,475
	a Recoverable Costs Allocated to Energy		7,133	7,113	7,092	7,072	7,051	7,031	7,053	7,032	7,011	6,991	6,970	6,949	84,498
	b Recoverable Costs Allocated to Demand		85,600	85,353	85,107	84,860	84,613	84,367	84,637	84,387	84,138	83,888	83,639	83,389	1,013,977
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		7,142	7,121	7,101	7,080	7,060	7,039	7,062	7,041	7,020	6,999	6,978	6,957	84,600
13	Retail Demand-Related Recoverable Costs (I)		83,232	82,992	82,753	82,513	82,273	82,034	82,296	82,053	81,811	81,568	81,325	81,083	985,933
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		90,374	90,114	89,853	89,593	89,333	89,073	89,358	89,094	88,831	88,567	88,304	88,040	1,070,533

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Plant Groundwater Investigation

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Crist Water Conservation Program

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	533,264	0	0	0	0	0	0	0	0	0	0	533,264
	c Retirements		0	0	298,319	0	0	0	0	0	0	0	0	0	298,319
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e PIS Adjustment		0	(533,264)	0	0	533,264	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		0	0	0	0	(1,560)	0	0	0	0	0	0	0	(1,560)
2	Plant-in-Service/Depreciation Base (B)	19,748,717	19,748,717	19,748,717	19,450,398	19,450,398	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	
3	Less: Accumulated Depreciation (C)	(6,413,268)	(6,479,098)	(6,544,927)	(6,311,939)	(6,376,774)	(6,444,947)	(6,511,559)	(6,578,171)	(6,644,783)	(6,711,395)	(6,778,008)	(6,844,620)	(6,911,232)	
4	CWIP - Non Interest Bearing	533,264	533,264	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	13,868,713	13,802,883	13,203,790	13,138,459	13,073,624	13,538,715	13,472,103	13,405,491	13,338,879	13,272,266	13,205,654	13,139,042	13,072,430	
6	Average Net Investment		13,835,798	13,503,337	13,171,125	13,106,041	13,306,170	13,505,409	13,438,797	13,372,185	13,305,573	13,238,960	13,172,348	13,105,736	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		63,700	62,169	60,640	60,340	61,262	62,179	64,358	64,039	63,720	63,401	63,082	62,763	751,655
	b Debt Component (Line 6 x Debt Component x 1/12)		16,077	15,691	15,305	15,229	15,462	15,693	14,097	14,027	13,958	13,888	13,818	13,748	176,993
8	Investment Expenses														
	a Depreciation (E)		65,829	65,829	65,332	64,835	66,612	66,612	66,612	66,612	66,612	66,612	66,612	66,612	794,722
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		145,606	143,689	141,277	140,404	143,336	144,484	145,068	144,679	144,290	143,901	143,512	143,123	1,723,370
	a Recoverable Costs Allocated to Energy		11,200	11,053	10,867	10,800	11,026	11,114	11,159	11,129	11,099	11,069	11,039	11,009	132,567
	b Recoverable Costs Allocated to Demand		134,406	132,636	130,409	129,604	132,310	133,370	133,909	133,550	133,191	132,832	132,473	132,114	1,590,803
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		11,214	11,066	10,880	10,813	11,039	11,128	11,172	11,143	11,113	11,083	11,053	11,023	132,726
13	Retail Demand-Related Recoverable Costs (I)		130,688	128,968	126,802	126,019	128,650	129,682	130,205	129,856	129,507	129,158	128,809	128,460	1,546,806
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		141,902	140,034	137,683	136,833	139,689	140,809	141,378	140,999	140,620	140,241	139,862	139,483	1,679,532

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs. Timing of CWIP transfers, under the new automated data environment, creates the need for catchup adjustments until fully implemented.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Plant NPDES Permit Compliance Programs

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		10,652	0	1,379,255	73,984	1,419,520	335,775	0	0	0	0	0	0	3,219,187
	b Clearings to Plant		403,812	35,511	1,382	0	0	2,778,482	0	0	0	0	0	0	3,219,187
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e PIS Adjustment		(403,812)	(35,511)	(1,382)	0	440,705	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustment		0	0	0	0	(289)	0	0	0	0	0	0	0	(289)
2	Plant-in-Service/Depreciation Base (B)	9,951,406	9,951,406	9,951,406	9,951,406	9,951,406	10,392,112	13,170,593	13,170,593	13,170,593	13,170,593	13,170,593	13,170,593	13,170,593	
3	Less: Accumulated Depreciation (C)	(2,953,894)	(2,989,281)	(3,024,668)	(3,060,055)	(3,095,442)	(3,132,587)	(3,174,074)	(3,220,192)	(3,266,310)	(3,312,427)	(3,358,545)	(3,404,662)	(3,450,780)	
4	CWIP - Non Interest Bearing	1,056	(392,104)	(427,615)	950,258	1,024,242	2,443,762	1,056	1,056	1,056	1,056	1,056	1,056	1,056	
5	Net Investment (Lines 2 + 3 + 4) (A)	6,998,568	6,570,021	6,499,123	7,841,609	7,880,206	9,703,286	9,997,574	9,951,457	9,905,339	9,859,222	9,813,104	9,766,986	9,720,869	
6	Average Net Investment		6,784,294	6,534,572	7,170,366	7,860,908	8,791,746	9,850,430	9,974,516	9,928,398	9,882,280	9,836,163	9,790,045	9,743,927	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		31,235	30,085	33,012	36,192	40,477	45,351	47,768	47,547	47,326	47,105	46,885	46,664	499,648
	b Debt Component (Line 6 x Debt Component x 1/12)		7,883	7,593	8,332	9,134	10,216	11,446	10,463	10,415	10,367	10,318	10,270	10,221	116,659
8	Investment Expenses														
	a Depreciation (E)		35,387	35,387	35,387	35,387	36,856	41,487	46,118	46,118	46,118	46,118	46,118	46,118	496,597
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		74,505	73,065	76,731	80,713	87,549	98,284	104,349	104,080	103,810	103,541	103,272	103,003	1,112,903
	a Recoverable Costs Allocated to Energy		5,731	5,620	5,902	6,209	6,735	7,560	8,027	8,006	7,985	7,965	7,944	7,923	85,608
	b Recoverable Costs Allocated to Demand		68,774	67,445	70,829	74,504	80,815	90,724	96,322	96,074	95,825	95,576	95,328	95,079	1,027,295
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		5,738	5,627	5,909	6,216	6,743	7,569	8,036	8,016	7,995	7,974	7,954	7,933	85,711
13	Retail Demand-Related Recoverable Costs (I)		66,872	65,580	68,870	72,444	78,580	88,215	93,658	93,416	93,175	92,933	92,691	92,450	998,883
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		72,610	71,207	74,779	78,660	85,322	95,784	101,694	101,432	101,170	100,907	100,645	100,383	1,084,594

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs. Timing of CWIP transfers, under the new automated data environment, creates the need for catchup adjustments until fully implemented.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Air Quality Compliance Program

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		258,626	377,494	316,304	39,535	549,804	197,198	498,481	1,056,326	1,235,345	627,654	178,134	2,871,141	8,206,042
	b Clearings to Plant		34,419	11,845	806,381	682,034	21,349	0	0	0	0	0	0	525,594	2,081,622
	c Retirements		40,957	0	374,957	282,271	89,201	600,000	0	0	0	0	0	250,000	1,637,386
	d Other		(129,681)	47,578	(54,597)	31,487	27,284	(88,211)	8,440	2,102	2,102	2,102	2,102	73,461	(75,832)
	e PIS Adjustments		(1,703,482)	1,472,003	(289)	(0)	231,971	0	0	0	0	0	0	0	202
	f Accumulated Depreciation Adjustments		(6,717)	(5,599)	0	0	1,720	0	0	0	0	0	0	0	(10,596)
2	Plant-in-Service/Depreciation Base (B)	1,343,294,490	1,341,584,470	1,343,068,318	1,343,499,454	1,343,899,217	1,344,063,335	1,343,463,335	1,343,463,335	1,343,463,335	1,343,463,335	1,343,463,335	1,343,463,335	1,343,738,929	
3	Less: Accumulated Depreciation (C)	(316,705,226)	(320,700,107)	(324,561,152)	(328,144,832)	(331,736,747)	(335,524,821)	(338,753,270)	(342,484,068)	(346,221,204)	(349,958,340)	(353,695,476)	(357,432,612)	(360,848,389)	
4	CWIP - Non Interest Bearing	2,015,378	2,239,585	2,605,234	2,115,157	1,472,658	2,001,113	2,198,311	2,696,792	3,753,118	4,988,463	5,616,117	5,794,250	8,139,797	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,028,604,642	1,023,123,948	1,021,112,401	1,017,469,779	1,013,635,127	1,010,539,627	1,006,908,377	1,003,676,059	1,000,995,249	998,493,458	995,383,976	991,824,973	991,030,338	
6	Average Net Investment		1,025,864,295	1,022,118,174	1,019,291,090	1,015,552,453	1,012,087,377	1,008,724,002	1,005,292,218	1,002,335,654	999,744,354	996,938,717	993,604,475	991,427,656	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,723,079	4,705,832	4,692,816	4,675,603	4,659,650	4,644,165	4,814,344	4,800,185	4,787,776	4,774,340	4,758,372	4,747,947	56,784,111
	b Debt Component (Line 6 x Debt Component x 1/12)		1,192,054	1,187,701	1,184,416	1,180,072	1,176,046	1,172,137	1,054,552	1,051,450	1,048,732	1,045,789	1,042,291	1,040,008	13,375,248
8	Investment Expenses														
	a Depreciation (E)		3,879,150	3,882,732	3,883,433	3,884,751	3,885,356	3,719,314	3,718,314	3,718,314	3,718,314	3,718,314	3,718,314	3,718,314	45,444,622
	b Amortization (F)		20,291	20,291	20,607	20,923	20,923	20,923	20,923	20,923	20,923	20,923	20,923	20,923	249,500
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		546,264	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	6,491,349
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,360,838	10,337,019	10,321,735	10,301,812	10,282,438	10,097,003	10,148,596	10,131,336	10,116,208	10,099,828	10,080,363	10,067,655	122,344,829
	a Recoverable Costs Allocated to Energy		796,988	795,155	793,980	792,447	790,957	776,693	780,661	779,334	778,170	776,910	775,413	774,435	9,411,141
	b Recoverable Costs Allocated to Demand		9,563,850	9,541,864	9,527,756	9,509,365	9,491,481	9,320,310	9,367,935	9,352,002	9,338,038	9,322,918	9,304,950	9,293,220	112,933,688
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		797,944	796,109	794,932	793,398	791,906	777,625	781,598	780,269	779,104	777,842	776,343	775,364	9,422,434
13	Retail Demand-Related Recoverable Costs (I)		9,299,340	9,277,961	9,264,244	9,246,361	9,228,972	9,062,535	9,108,843	9,093,351	9,079,773	9,065,072	9,047,601	9,036,194	109,810,247
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,097,284	10,074,071	10,059,176	10,039,759	10,020,878	9,840,160	9,890,441	9,873,620	9,858,876	9,842,914	9,823,944	9,811,559	119,232,681

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs. Timing of CWIP transfers, under the new automated data environment, creates the need for catchup adjustments until fully implemented.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: General Water Quality

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		144,305	0	0	0	0	0	0	0	0	0	0	0	144,305
	b Clearings to Plant		144,305	0	0	0	0	0	0	0	0	0	0	0	144,305
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	852,461	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	
3	Less: Accumulated Depreciation (C)	(50,034)	(53,116)	(56,438)	(59,761)	(63,084)	(66,406)	(69,729)	(73,051)	(76,374)	(79,696)	(83,019)	(86,341)	(89,664)	
4	CWIP - Non Interest Bearing	396,464	396,464	396,464	396,464	396,464	396,464	396,464	396,464	396,464	396,464	396,464	396,464	396,464	
5	Crist Closed Ash Landfill Reg Asset	0	2,401,279	2,451,043	2,474,765	2,459,149	2,498,268	2,590,007	2,611,217	2,630,416	2,636,964	2,643,513	7,000,262	8,839,289	
6	Net Investment (Lines 2 + 3 + 4) (A)	1,198,891	3,741,393	3,787,835	3,808,234	3,789,296	3,825,092	3,913,508	3,931,396	3,947,272	3,950,498	3,953,725	8,307,151	10,142,855	
7	Average Net Investment		2,470,142	3,764,614	3,798,035	3,798,765	3,807,194	3,869,300	3,922,452	3,939,334	3,948,885	3,952,112	6,130,438	9,225,003	
8	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		11,373	17,332	17,486	17,490	17,528	17,814	18,785	18,865	18,911	18,927	29,359	44,179	248,048
	b Debt Component (Line 6 x Debt Component x 1/12)		2,870	4,374	4,413	4,414	4,424	4,496	4,115	4,132	4,142	4,146	6,431	9,677	57,635
9	Investment Expenses														
	a Depreciation (E)		3,082	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	39,630
	b Amortization (F)		4,009	8,114	8,264	8,305	8,372	8,451	8,451	8,451	8,451	8,451	8,451	8,451	96,221
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	57,878	31,986	(7,310)	47,490	100,190	29,661	27,650	15,000	15,000	4,365,200	1,847,477	6,530,222
10	Total System Recoverable Expenses (Lines 7 + 8)		21,334	33,143	33,486	33,531	33,647	34,084	34,673	34,771	34,827	34,846	47,563	65,629	441,535
	a Recoverable Costs Allocated to Energy		1,641	2,549	2,576	2,579	2,588	2,622	2,667	2,675	2,679	2,680	3,659	5,048	33,964
	b Recoverable Costs Allocated to Demand		19,693	30,594	30,910	30,952	31,059	31,462	32,006	32,097	32,148	32,166	43,904	60,581	407,571
11	Energy Jurisdictional Factor (J)		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	Demand Jurisdictional Factor (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
13	Retail Energy-Related Recoverable Costs (H)		1,643	2,553	2,579	2,582	2,591	2,625	2,670	2,678	2,682	2,684	3,663	5,054	34,005
14	Retail Demand-Related Recoverable Costs (I)		19,148	29,748	30,055	30,096	30,200	30,592	31,121	31,209	31,259	31,276	42,690	58,905	396,299
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		20,791	32,300	32,634	32,678	32,791	33,217	33,791	33,887	33,941	33,960	46,353	63,960	430,304

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Coal Combustion Residuals

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		3,015,036	1,132,005	1,467,296	3,483,565	7,458,849	5,411,990	1,658,469	4,798,457	3,264,214	2,138,421	2,432,472	3,022,143	39,282,917
	b Clearings to Plant		(658,051)	(231,446)	(640,898)	(57,163)	17,118,089	0	9,131,445	123,473	248,610	16,808,710	20,946,583	879,544	63,668,895
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	118,910	80,798	60,495	231,814	2,747,811	332,860	582,860	582,860	582,860	407,346	740,954	6,469,568
	e PIS Adjustments		0	0	0	0	(14,664,653)	0	0	0	0	0	0	0	(14,664,653)
	f Accumulated Depreciation Adjustments		(76,099)	0	0	0	(183,226)	0	0	0	0	0	0	0	(259,325)
2	Plant-in-Service/Depreciation Base (B)	19,585,347	18,927,296	18,695,850	18,054,952	17,997,788	20,451,224	35,115,877	44,247,322	44,370,795	44,619,405	61,428,115	82,374,697	83,254,241	
3	Less: Accumulated Depreciation (C)	(34,638,588)	(34,810,019)	(34,785,539)	(34,798,375)	(34,830,875)	(34,877,453)	(32,248,908)	(32,060,171)	(31,633,002)	(31,206,299)	(30,823,743)	(30,701,019)	(30,286,270)	
4	CWIP - Non Interest Bearing	72,965,701	76,638,788	78,002,239	80,110,433	83,651,161	73,991,922	79,403,912	71,930,936	76,605,920	79,621,524	64,951,235	46,437,125	48,579,723	
5	Ash Pond Closure Regulatory Asset	11,167,690	11,534,778	11,925,968	12,346,551	12,651,770	13,673,165	14,856,054	21,834,714	26,230,296	30,829,691	34,706,544	37,716,239	40,179,026	
6	Net Investment (Lines 2 + 3 + 4) (A)	69,080,149	72,290,842	73,838,518	75,713,560	79,469,845	73,238,858	97,126,935	105,952,802	115,574,009	123,864,320	130,262,152	135,827,042	141,726,721	
7	Average Net Investment		70,685,496	73,064,680	74,776,039	77,591,702	76,354,351	85,182,896	101,539,868	110,763,405	119,719,165	127,063,236	133,044,597	138,776,881	
8	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		325,436	336,390	344,269	357,232	351,535	392,182	486,274	530,446	573,335	608,506	637,151	664,602	5,607,359
	b Debt Component (Line 6 x Debt Component x 1/12)		82,137	84,901	86,890	90,162	88,724	98,983	106,515	116,191	125,585	133,289	139,564	145,577	1,298,517
9	Investment Expenses														
	a Depreciation (E)		40,471	39,570	38,774	38,134	40,305	64,405	89,262	100,831	101,296	145,442	229,761	271,344	1,199,596
	b Amortization (F)		0	0	118,169	21,046	22,188	23,058	23,058	23,058	23,058	23,058	23,058	23,058	322,806
	c Dismantlement		54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	658,328
	d Property Taxes		7,248	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	74,053
	e Other (G)		367,088	391,191	538,752	326,265	1,043,583	1,205,947	7,001,718	4,418,640	4,622,452	3,899,911	3,032,752	2,485,844	29,334,142
10	Total System Recoverable Expenses (Lines 7 + 8)		510,153	521,795	649,036	567,508	563,686	639,561	766,043	831,459	884,208	971,229	1,090,467	1,165,515	9,160,660
	a Recoverable Costs Allocated to Energy		39,243	40,138	49,926	43,654	43,360	49,197	58,926	63,958	68,016	74,710	83,882	89,655	704,666
	b Recoverable Costs Allocated to Demand		470,910	481,657	599,110	523,854	520,326	590,364	707,117	767,501	816,192	896,519	1,006,585	1,075,860	8,455,994
11	Energy Jurisdictional Factor (J)		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	Demand Jurisdictional Factor (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
13	Retail Energy-Related Recoverable Costs (H)		39,290	40,186	49,986	43,707	43,413	49,256	58,997	64,035	68,098	74,800	83,983	89,763	705,512
14	Retail Demand-Related Recoverable Costs (I)		457,886	468,335	582,540	509,366	505,935	574,036	687,560	746,274	793,618	871,724	978,746	1,046,105	8,222,124
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		497,176	508,521	632,526	553,072	549,348	623,292	746,557	810,309	861,716	946,523	1,062,729	1,135,867	8,927,635

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs. Timing of CWIP transfers, under the new automated data environment, creates the need for catchup adjustments until fully implemented.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Steam Electric Effluent Limitations Guidelines

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		75,272	9,951	10,627	26,521	21,637	24,432	14,768	14,768	14,768	14,768	14,768	14,768	257,048
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e PIS Adjustments		(131)	0	0	0	131	0	0	0	0	0	0	0	0
	f Accumulated Depreciation Adjustments		(1,534)	0	0	0	(5,972)	0	0	0	0	0	0	0	(7,506)
2	Plant-in-Service/Depreciation Base (B)	6,042,460	6,042,329	6,042,329	6,042,329	6,042,329	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	
3	Less: Accumulated Depreciation (C)	(410,569)	(430,962)	(449,821)	(468,681)	(487,540)	(513,077)	(531,937)	(550,797)	(569,656)	(588,516)	(607,375)	(626,235)	(645,095)	
4	CWIP - Non Interest Bearing	653,027	728,298	738,250	748,876	775,397	797,034	821,466	836,234	851,002	865,770	880,538	895,306	910,074	
5	Net Investment (Lines 2 + 3 + 4) (A)	6,284,918	6,339,666	6,330,758	6,322,525	6,330,186	6,326,417	6,331,989	6,327,898	6,323,806	6,319,714	6,315,623	6,311,531	6,307,440	
6	Average Net Investment		6,312,292	6,335,212	6,326,641	6,326,356	6,328,301	6,329,203	6,329,943	6,325,852	6,321,760	6,317,669	6,313,577	6,309,486	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		29,062	29,167	29,128	29,127	29,135	29,140	30,314	30,295	30,275	30,255	30,236	30,216	356,349
	b Debt Component (Line 6 x Debt Component x 1/12)		7,335	7,362	7,352	7,351	7,353	7,355	6,640	6,636	6,632	6,627	6,623	6,619	83,883
8	Investment Expenses														
	a Depreciation (E)		18,859	18,859	18,859	18,859	19,565	18,860	18,860	18,860	18,860	18,860	18,860	18,860	227,019
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		237	197	197	197	197	197	197	197	197	197	197	197	2,407
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		55,493	55,585	55,536	55,534	56,251	55,551	56,011	55,987	55,963	55,939	55,916	55,892	669,659
	a Recoverable Costs Allocated to Energy		4,269	4,276	4,272	4,272	4,327	4,273	4,309	4,307	4,305	4,303	4,301	4,299	51,512
	b Recoverable Costs Allocated to Demand		51,224	51,309	51,264	51,262	51,924	51,278	51,703	51,681	51,658	51,636	51,614	51,592	618,147
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		4,274	4,281	4,277	4,277	4,332	4,278	4,314	4,312	4,310	4,308	4,306	4,305	51,574
13	Retail Demand-Related Recoverable Costs (I)		49,808	49,890	49,846	49,845	50,488	49,860	50,273	50,251	50,230	50,208	50,187	50,165	601,050
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		54,081	54,171	54,123	54,122	54,820	54,138	54,586	54,563	54,540	54,516	54,493	54,470	652,624

Notes:
(A) Due to automation of Gulf Clause schedules and corresponding calculations, we have made adjustments to Plant in Service and Depreciation expense in order properly account for all ECRC capital costs. Timing of CWIP transfers, under the new automated data environment, creates the need for catchup adjustments until fully implemented.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: 316(b) Intake Structure Regulation

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Expenditures/Additions		31,976	372,474	188,149	184,306	12,795	23,555	23,555	23,555	682,418	900,343	1,387,068	190,273	4,020,468
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		3,198	36,146	18,815	0	0	0	0	0	0	0	0	0	58,158
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	29,428	32,625	68,771	87,586	87,586	87,586	87,586	87,586	87,586	87,586	87,586	87,586	87,586	
4	CWIP - Non Interest Bearing	318,704	350,680	723,154	911,303	1,095,610	1,108,405	1,131,960	1,155,515	1,179,070	1,861,488	2,761,831	4,148,899	4,339,172	
5	Net Investment (Lines 2 + 3 + 4) (A)	348,132	383,305	791,925	998,889	1,183,196	1,195,990	1,219,546	1,243,101	1,266,656	1,949,074	2,849,417	4,236,485	4,426,757	
6	Average Net Investment		365,718	587,615	895,407	1,091,042	1,189,593	1,207,768	1,231,323	1,254,878	1,607,865	2,399,245	3,542,951	4,331,621	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,684	2,705	4,122	5,023	5,477	5,561	5,897	6,010	7,700	11,490	16,967	20,744	93,380
	b Debt Component (Line 6 x Debt Component x 1/12)		425	683	1,040	1,268	1,382	1,403	1,292	1,316	1,687	2,517	3,717	4,544	21,274
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,109	3,388	5,163	6,291	6,859	6,964	7,188	7,326	9,387	14,007	20,684	25,288	114,654
	a Recoverable Costs Allocated to Energy		162	261	397	484	528	536	553	564	722	1,077	1,591	1,945	8,820
	b Recoverable Costs Allocated to Demand		1,947	3,128	4,766	5,807	6,332	6,428	6,636	6,762	8,665	12,929	19,093	23,343	105,834
10	Energy Jurisdictional Factor (J)		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 (K)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (H)		162	261	398	484	528	536	554	564	723	1,079	1,593	1,948	8,830
13	Retail Demand-Related Recoverable Costs (I)		1,893	3,041	4,634	5,646	6,156	6,251	6,452	6,575	8,425	12,572	18,565	22,697	102,907
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,055	3,302	5,032	6,131	6,685	6,787	7,006	7,140	9,148	13,650	20,158	24,645	111,737

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 9a x Line 10 x line loss multiplier
(I) Line 9b x Line 11.
(J) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(K) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Project: Annual NOx Allowances

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Working Capital														
	a FERC 158.1 Allowance Inventory	5,768	4,839	5,125	5,125	4,950	4,950	4,856	4,776	4,676	4,590	4,530	4,472	4,405	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Reg. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	5,768	4,839	5,125	5,125	4,950	4,950	4,856	4,776	4,676	4,590	4,530	4,472	4,405	
4	Average Net Working Capital Balance		5,303	4,982	5,125	5,038	4,950	4,903	4,816	4,726	4,633	4,560	4,501	4,439	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		24	23	24	23	23	23	23	23	22	22	22	21	272
	b Debt Component (Line 4 x Debt Component x 1/12)		6	6	6	6	6	6	5	5	5	5	5	5	64
6	Total Return Component (D)		31	29	30	29	29	28	28	28	27	27	26	26	336
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual NOx Allowance Expense		929	(286)	0	176	0	93	81	99	87	60	58	67	1,362
8	Net Expenses (E)		929	(286)	0	176	0	93	81	99	87	60	58	67	1,362
9	Total System Recoverable Expenses (Lines 6 + 8)		959	(258)	30	205	29	122	109	127	114	87	84	93	1,699
	a Recoverable Costs Allocated to Energy		931	(284)	2	178	2	96	83	102	89	62	60	69	1,388
	b Recoverable Costs Allocated to Demand		28	27	27	27	26	26	26	25	25	25	24	24	310
10	Energy Jurisdictional Factor (F)		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 (G)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (B)		932	(284)	2	178	2	96	83	102	89	62	60	69	1,390
13	Retail Demand-Related Recoverable Costs (C)		27	26	27	26	26	25	25	25	24	24	24	23	302
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		960	(259)	29	204	28	121	108	126	113	86	83	92	1,692

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.
(F) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(G) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: SO2 Allowances

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	24	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	6,302,888	6,298,581	6,297,186	6,297,186	6,278,336	6,278,336	6,276,841	6,275,653	6,274,455	6,273,325	6,272,698	6,272,577	6,272,417	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(161)	(147)	(147)	(147)	(167)	(163)	(158)	(154)	(149)	(145)	(140)	(136)	(131)	
3	Total Working Capital Balance	6,302,727	6,298,434	6,297,039	6,297,039	6,278,169	6,278,174	6,276,683	6,275,499	6,274,306	6,273,180	6,272,557	6,272,441	6,272,286	
4	Average Net Working Capital Balance		6,300,581	6,297,737	6,297,039	6,287,604	6,278,171	6,277,428	6,276,091	6,274,902	6,273,743	6,272,869	6,272,499	6,272,363	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		29,008	28,995	28,992	28,948	28,905	28,901	30,056	30,051	30,045	30,041	30,039	30,038	354,018
	b Debt Component (Line 4 x Debt Component x 1/12)		7,321	7,318	7,317	7,306	7,295	7,294	6,584	6,582	6,581	6,580	6,580	6,580	83,339
6	Total Return Component (D)		36,329	36,313	36,309	36,254	36,200	36,196	36,640	36,633	36,626	36,621	36,619	36,618	437,357
7	Expenses														
	a Gains		(15)	0	0	(3)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(54)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		4,307	1,395	0	18,849	0	1,495	1,188	1,198	1,130	627	121	160	30,471
8	Net Expenses (E)		4,293	1,395	0	18,846	(5)	1,491	1,184	1,193	1,126	622	117	155	30,417
9	Total System Recoverable Expenses (Lines 6 + 8)		40,622	37,708	36,309	55,100	36,195	37,687	37,824	37,826	37,752	37,244	36,735	36,773	467,774
	a Recoverable Costs Allocated to Energy		7,087	4,189	2,793	21,635	2,780	4,275	4,002	4,011	3,943	3,439	2,933	2,972	64,060
	b Recoverable Costs Allocated to Demand		33,535	33,519	33,516	33,466	33,415	33,411	33,821	33,815	33,809	33,804	33,802	33,801	403,714
10	Energy Jurisdictional Factor (F)		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 (G)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (B)		7,096	4,194	2,796	21,661	2,783	4,280	4,007	4,016	3,948	3,444	2,937	2,975	64,137
13	Retail Demand-Related Recoverable Costs (C)		32,607	32,592	32,589	32,540	32,491	32,487	32,886	32,880	32,874	32,869	32,867	32,866	392,549
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		39,703	36,786	35,385	54,200	35,275	36,768	36,893	36,896	36,822	36,313	35,804	35,842	456,686

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.
(F) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
The The demand jurisdictional factors for each month are based on actual 2018 retail kilowatt-hour sales expressed as a percentage of 2018 total territorial kilowatt-hour sales, pending final calculation of the stratified jurisdictional demand factors.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Seasonal NOx Allowances

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	85,000	0	85,000
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Working Capital														
	a FERC 158.1 Allowance Inventory	2,917	2,941	2,941	2,941	2,973	2,973	2,598	2,180	1,755	1,372	1,372	86,372	86,372	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	2,917	2,941	2,941	2,941	2,973	2,973	2,598	2,180	1,755	1,372	1,372	86,372	86,372	
4	Average Net Working Capital Balance		2,929	2,941	2,941	2,957	2,973	2,785	2,389	1,967	1,563	1,372	43,872	86,372	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		13	14	14	14	14	13	11	9	7	7	210	414	739
	b Debt Component (Line 4 x Debt Component x 1/12)		3	3	3	3	3	3	3	2	2	1	46	91	165
6	Total Return Component (D)		17	17	17	17	17	16	14	11	9	8	256	504	904
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Seasonal NOx Allowance Expense		(24)	0	0	(32)	0	375	417	426	383	0	0	0	1,545
8	Net Expenses (E)		(24)	0	0	(32)	0	375	417	426	383	0	0	0	1,545
9	Total System Recoverable Expenses (Lines 6 + 8)		(7)	17	17	(15)	17	391	431	437	392	8	256	504	2,449
	a Recoverable Costs Allocated to Energy		(23)	2	1	(31)	1	376	418	427	383	1	20	39	1,615
	b Recoverable Costs Allocated to Demand		16	16	16	16	16	15	13	11	8	7	236	465	834
10	Energy Jurisdictional Factor (F)		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 (G)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
12	Retail Energy-Related Recoverable Costs (B)		(23)	2	1	(31)	1	377	419	427	384	1	20	39	1,617
13	Retail Demand-Related Recoverable Costs (C)		15	15	15	15	15	14	13	10	8	7	230	453	811
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		(8)	17	17	(16)	17	391	432	437	392	8	250	491	2,428

Notes:
(A) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(B) Line 9a x Line 10 x line loss multiplier
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 3P.
(E) Line 8 is reported on Schedule 2P.
(F) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(G) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM 42-8E

JANUARY 2020 THROUGH DECEMBER 2020
For Program: Regulatory Asset Smith Units 1 & 2

0	0	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12-Month Total
1	Regulatory Asset Balance 182.2 (B)	18,498,355	18,498,355	18,379,776	18,261,197	18,142,617	18,024,038	17,905,459	17,786,880	17,668,301	17,549,721	17,431,142	17,312,563	17,193,984	
2	Less Amortization (C)	0	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	
3	Net Regulatory Asset Balance (Lines 1 + 2) (A)	18,498,355	18,379,776	18,261,197	18,142,617	18,024,038	17,905,459	17,786,880	17,668,301	17,549,721	17,431,142	17,312,563	17,193,984	17,075,405	
4	Average Regulatory Asset Balance		18,439,065	18,320,486	18,201,907	18,083,328	17,964,749	17,846,169	17,727,590	17,609,011	17,490,432	17,371,853	17,253,273	17,134,694	
5	Return on Average Regulatory Asset Balance														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		84,893	84,348	83,802	83,256	82,710	82,164	84,897	84,330	83,762	83,194	82,626	82,058	1,002,038
	b Debt Component (Line 6 x Debt Component x 1/12)		21,426	21,288	21,151	21,013	20,875	20,737	18,596	18,472	18,347	18,223	18,099	17,974	236,202
6	Amortization Expense														
	a Recoverable Costs Allocated to Energy		118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	1,422,950
	b Other (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total System Recoverable Expenses (Lines 5 + 6)		224,899	224,215	223,531	222,848	222,164	221,480	222,073	221,381	220,688	219,996	219,304	218,612	2,661,190
	a Recoverable Costs Allocated to Energy		17,300	17,247	17,195	17,142	17,090	17,037	17,083	17,029	16,976	16,923	16,870	16,816	204,707
	b Recoverable Costs Allocated to Demand		207,599	206,968	206,337	205,706	205,074	204,443	204,990	204,351	203,712	203,073	202,434	201,795	2,456,484
8	Energy Jurisdictional Factor (I)		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
9	Demand Jurisdictional Factor (J)		0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	0.9723427	
10	Retail Energy-Related Recoverable Costs (G)		17,321	17,268	17,215	17,163	17,110	17,057	17,103	17,050	16,996	16,943	16,890	16,836	204,953
11	Retail Demand-Related Recoverable Costs (H)		201,857	201,244	200,630	200,016	199,403	198,789	199,321	198,700	198,078	197,457	196,836	196,214	2,388,544
12	Total Jurisdictional Recoverable Costs (Lines 10 + 11)		219,178	218,512	217,845	217,179	216,513	215,846	216,424	215,749	215,075	214,400	213,725	213,051	2,593,496

Notes:
(A) End of period Regulatory Asset Balance.
(B) Beginning of period Regulatory Asset Balance.
(C) Regulatory Asset has a 15 year amortization period.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Regulatory Asset has a 15 year amortization period.
(F) Description and reason for "Other" adjustments to regulatory asset.
(G) Line 7a x Line 8 x line loss multiplier
(H) Line 7b x Line 9.
(I) The energy jurisdictional factors for each month are the same as that used in the fuel clause, or 100%, pending final calculation of the stratified jurisdictional energy factors.
(J) The demand jurisdictional is based upon Gulf Power's 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

2020 Depreciation Schedule **Form 42-8E**

Project Number	Project	Plant	Amortization /Depreciation	Plant	Plant	Monthly Depr Rate
1	401-Air Quality Assurance Testing	Other	A	83,954	83,954	
2	402-Crist 5, 6 & 7 Precipitator Projects	Crist	D	33,657,087	33,657,087	0.3333333
3	403-Crist 7 Flue Gas Conditioning	Crist	D	0	0	0.3333333
4	404-Low NOx Burners, Crist 6 & 7	Crist Amort	A	143,759	143,759	0.0119048
4	404-Low NOx Burners, Crist 6 & 7	Crist	D	13,384,173	13,384,173	0.3333333
5	405-CEMS - Plants Crist & Daniel	Crist	D	4,086,636	4,086,636	0.3333333
5	405-CEMS - Plants Crist & Daniel	Crist Amort	A	0	0	0.0119048
5	405-CEMS - Plants Crist & Daniel	Daniel	D	67,461	67,461	0.2500000
5	405-CEMS - Plants Crist & Daniel	Daniel CEMs	D	558,686	558,686	0.2500000
6	406-Substation Contamination Remediation	Ft Walton	D	2,775,019	2,775,019	0.2583333
6	406-Substation Contamination Remediation	Laguna	D	339,156	339,156	0.1416667
6	406-Substation Contamination Remediation	Distribution	D	131,648	608,648	0.2583333
7	407-Raw Water Well Flowmeters Plants Crist & Smith	Crist	D	149,950	149,950	0.3333333
7	407-Raw Water Well Flowmeters Plants Crist & Smith	Smith (355)	D	0	0	0.3916667
8	408-Crist Cooling Tower Cell	Crist	D	0	0	0.3333333
9	409-Crist Dechlorination System	Crist	D	380,697	380,697	0.3333333
10	410-Crist Diesel Fuel Oil Remediation	Crist	D	20,968	20,968	0.3333333
11	411-Crist Bulk Tanker Unloading Second Containment	Crist	D	101,495	101,495	0.3333333
12	412-Crist IWW Sampling System	Crist	D	59,543	59,543	0.3333333
13	413-Sodium Injection System	Crist	D	284,622	284,622	0.3333333
13	413-Sodium Injection System	Smith	D	0	0	
14	414-Smith Stormwater Collection System	Smith (355)	D	2,764,379	2,764,379	0.3916667
15	415-Smith Waste Water Treatment Facility	Smith (355)	D	178,962	643,620	0.3916667
16	416-Daniel Ash Management Project	Daniel	D	14,939,561	14,939,561	0.2500000
16	416-Daniel Ash Management Project	Other	D	0	0	
17	417-Smith Water Conservation	Smith (355)	D	21,018,243	21,590,761	0.3916667
18	418-Underground Fuel Tank Replacement	Other	D	0	0	
19	419-Crist FDEP Agreement for Ozone Attainment	Crist	D	118,758,299	118,758,299	0.3333333
19	419-Crist FDEP Agreement for Ozone Attainment	Crist Amort	A	825,620	825,620	0.0119048
20	420-SPCC Compliance	Crist	D	919,836	919,836	0.3333333
20	420-SPCC Compliance	Other Amort	A	13,195	13,195	0.0119048
20	420-SPCC Compliance	Smith (355)	D	14,895	14,895	0.3916667
21	421-Crist Common FTIR Monitor	Crist	D	0	0	0.3333333
22	422-Precipitator Upgrades for CAM Compliance	Crist	D	13,895,639	13,895,639	0.3333333
23	423-Plant Groundwater Investigation	Other	D	0	0	
24	424-Crist Water Conservation	Crist	D	19,748,717	19,983,662	0.3333333
25	425-Plant NPDES Permit Compliance Projects	Crist	D	6,153,140	9,372,327	0.3333333
25	425-Plant NPDES Permit Compliance Projects	Smith (355)	D	3,798,266	3,798,266	0.3916667
26	426-Air Quality Compliance Program	Crist	D	193,354,217	193,354,419	0.3333333
26	426-Air Quality Compliance Program	Crist SCR	D	65,329	65,329	0.3333333
26	426-Air Quality Compliance Program	Crist SCR Amort	A	105,607	105,607	0.0119048
26	426-Air Quality Compliance Program	Crist Scrubber	D	586,883,361	587,330,241	0.3333333
26	426-Air Quality Compliance Program	Crist Scrubber Amort	A	730,203	730,203	0.0119048
26	426-Air Quality Compliance Program	Crist Scrubber (353)	D	2,986,187	2,986,187	0.2333333
26	426-Air Quality Compliance Program	Crist Scrubber (352)	D	176,690	176,690	0.1416667
26	426-Air Quality Compliance Program	Crist Scrubber (354)	D	565,062	565,062	0.1666667
26	426-Air Quality Compliance Program	Crist Scrubber (355)	D	502,662	502,662	0.3833333
26	426-Air Quality Compliance Program	Crist Scrubber (356)	D	576,009	576,009	0.2166667
26	426-Air Quality Compliance Program	Daniel	D	13,882,987	13,882,987	0.2500000
26	426-Air Quality Compliance Program	Daniel 1 Scrubber	D	360,297,878	360,582,168	0.2500000
26	426-Air Quality Compliance Program	Daniel 2 Scrubber	D	0	0	0.2500000
26	426-Air Quality Compliance Program	Scherer	D	15,044,458	14,674,528	0.1833333
26	426-Air Quality Compliance Program	Scherer Scrubber	D	72,289,440	72,289,504	0.1833333
26	426-Air Quality Compliance Program	Scherer Scrubber Amort	A	20,761	20,761	0.0119048
26	426-Air Quality Compliance Program	Scherer Scrubber (352)	D	32,707	32,707	0.1416667
26	426-Air Quality Compliance Program	Scherer Scrubber (353)	D	1,599,066	1,599,066	0.2333333
26	426-Air Quality Compliance Program	Scherer Baghouse	D	46,154,432	46,154,432	0.1833333
26	426-Air Quality Compliance Program	Scherer SCR	D	47,797,695	47,880,628	0.1833333
26	426-Air Quality Compliance Program	Scholz	D	0	0	
26	426-Air Quality Compliance Program	Smith	D	229,742	229,742	0.5250000
27	427-General Water Quality	Crist	D	852,461	996,766	0.3333333
27	427-General Water Quality	Crist Sampling Boat	D	0	0	0.0166667
28	428-Coal Combustion Residuals	Crist	D	790,872	675,957	0.3333333
28	428-Coal Combustion Residuals	Daniel	D	104,724	21,243,089	0.2500000
28	428-Coal Combustion Residuals	Scherer	D	16,088,112	29,280,122	0.1833333
28	428-Coal Combustion Residuals	Scherer	L	0	0	
28	428-Coal Combustion Residuals	Scholz	D	0	0	
28	428-Coal Combustion Residuals	Smith	D	0	0	
28	428-Coal Combustion Residuals	Smith (355)	D	2,601,638	2,601,638	0.3916667
28	428-Coal Combustion Residuals	Smith Pond Closure	D	0	29,453,436	0.5250000
28	428-Coal Combustion Residuals	Scholz Pond Closure	D	0	0	
28	428-Coal Combustion Residuals	CCR-C	D	0	0	
28	428-Coal Combustion Residuals	CCR-D	D	0	0	
28	428-Coal Combustion Residuals	CCR-S	D	0	0	
29	429-Steam Electric Effluent Limitations Guidelines	Crist	D	5,657,885	5,657,885	0.3333333
29	429-Steam Electric Effluent Limitations Guidelines	Scherer	D	384,575	384,575	0.1833333
30	430-316(B) Intake Structure Regulation	Smith (355)	D	0	0	0.3916667
		Total		1,629,028,360	1,698,254,307	

Form 42-9E

January 2020 - June 2020
FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Long-Term Debt	894,848	34.5416	3.91	1.3519	1.3519	
2	Short-Term Debt	20,976	0.8097	2.96	0.0240	0.0240	
3	Preferred Stock	0	0.0000	0.00	0.0000	0.0000	
4	Common Stock	1,053,681	40.6728	10.25	4.1690	5.5234	
5	Customer Deposits	22,119	0.8538	2.08	0.0178	0.0178	
6	Deferred Taxes	598,399	23.0986				
7	Investment Tax Credit	608	0.0235	7.34	0.0017	0.0021	
8	Total	2,590,631	100.0000		5.5644	6.9192	0.5766
	ITC Component:						
9	Debt	894,848	45.9243	3.91	1.7974	0.0004	
10	Equity-Preferred	0	0.0000	0.00	0.0000	0.0000	
11	-Common	1,053,681	54.0757	10.25	5.5428	0.0017	
12		1,948,530	100.0000		7.3402	0.0021	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.3941	0.1162
14	Total Equity Component (Lines 3, 4, 10, and 11)					5.5251	0.4604
15	Total Revenue Requirement Rate of Return					6.9192	0.5766

Column:

(1) Based on the May 2019 Surveillance Report, Schedule 4.
Adjusted to achieve the 53.5% equity ratio as prescribed in the 2018 Tax Reform Settlement Agreement in Docket No. 20180039-EI.

(2) Column (1) / Total Column (1)

(3) Based on the May 2019 Surveillance Report, Schedule 4.

(4) Column (2) x Column (3)

(5) For equity components: Column (4) / (1-.245218); 24.5218% = effective income tax rate
For debt components: Column (4)

(6) Column (5) /12

Form 42-9E

January 2020 - June 2020
FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Long-Term Debt	877,077	31.6409	3.76	1.1912	1.1912	
2	Short-Term Debt	141,485	5.1041	0.92	0.0470	0.0470	
3	Preferred Stock	0	0.0000	0.00	0.0000	0.0000	
4	Common Stock	1,171,867	42.2754	10.25	4.3332	5.7410	
5	Customer Deposits	20,015	0.7220	2.69	0.0194	0.0194	
6	Deferred Taxes	558,907	20.1627				
7	Investment Tax Credit	2,632	0.0949	7.47	0.0071	0.0071	
8	Total	2,771,983	100.0000		5.5979	7.0057	0.5838
	ITC Component:						
9	Debt	877,077	42.8063	3.76	1.6116	0.0015	
10	Equity-Preferred	0	0.0000	0.00	0.0000	0.0000	
11	-Common	1,171,867	57.1937	10.25	5.8624	0.0056	
12		2,048,944	100.0000		7.4740	0.0071	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.2591	0.1049
14	Total Equity Component (Lines 3, 4, 10, and 11)					5.7466	0.4789
15	Total Revenue Requirement Rate of Return					7.0057	0.5838

Column:

(1) Based on the May 2020 Surveillance Report, Schedule 4.
Adjusted to achieve the 53.5% equity ratio as prescribed in the 2018 Tax Reform Settlement Agreement in Docket No. 20180039-EI.

(2) Column (1) / Total Column (1)

(3) Based on the May 2019 Surveillance Report, Schedule 4.

(4) Column (2) x Column (3)

(5) For equity components: Column (4) / (1-.245218); 24.5218% = effective income tax rate
For debt components: Column (4)

(6) Column (5) /12

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

FORM: 42-1P

JANUARY 2021 THROUGH DECEMBER 2021

	Energy	12 CP Demand	NCP Demand	Total
1. Total Jurisdictional Revenue Requirements for the Projected Period				
a. Projected O&M Activities [a]	$24,904,294	$3,991,935	$3,002,039	$31,898,269
b. Projected Capital Projects [b]	$12,733,690	$152,621,140	$381,909	$165,736,739
c. Total Jurisdictional Revenue Requirements [c]	$37,637,985	$156,613,074	$3,383,948	$197,635,007
2. True-up for Estimated Over/(Under) Recovery [d]	$2,553,443	$283,716		$2,837,159
3. Final True-up Over/(Under) [e]	$5,302,659	$589,184		$5,891,843
4. Total Jurisdictional Amount to be Recovered/(Refunded) [f]	$29,781,883	$155,740,174	$3,383,948	$188,906,006
5. Total Projected Jurisdictional Amount Adjusted for Taxes [g]	$29,803,326	$155,852,307	$3,386,385	$189,042,018

[a] Form 42-2P pg. 3, Columns 6 through 8; Energy X Line Loss Multiplier 1.0012
[b] Form 42-3P pg. 6, Columns 6 through 8; Energy X Line Loss Multiplier 1.0012
[c] Lines 1a + 1b
[d] For the current period January 2020 - December 2020 (Form 42-1E, Line 4, filed on July 31, 2020)
[e] For the period January 2019 - December 2019 (Schedule 1A, Line 3, filed on April 1, 2020)
[f] (Line 1 - Line 2 - Line 3)
[g] Line 4 x Revenue Tax Multiplier 1.00072

Note: Allocation to energy and demand in each period are in proportion to the respective period split of costs.
True-up costs are split in proportion to the split of actual demand-related and energy-related costs from respective true-up periods.

Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 17
PARTY: RLH-3
DESCRIPTION: Environmental Cost Recovery Projections - January 2021 - December 2021 Commission Forms 42-1P throug...

Docket 20200007-EI
2021 ECRC Projections
RLH-3, Page 1 of 105

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

JANUARY 2021 THROUGH DECEMBER 2021
O&M ACTIVITIES

O&M Project	Strata	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
2 - Air Emission Fees	Base	$13,777	$13,777	$104,323	$13,777	$13,777	$13,777	$13,777	$13,777	$13,777	$13,777	$13,777	$13,823	$255,915
2 - Air Emission Fees	Intermediate	$0	$0	$14,926	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,926
2 - Air Emission Fees	Peaking	$0	$0	$4,615	$3,774	$0	$0	$0	$0	$0	$0	$0	$0	$8,389
3 - Title V	Base	$8,360	$12,923	$10,436	$8,611	$8,611	$10,436	$13,174	$8,611	$10,436	$13,174	$8,611	$14,999	$128,382
3 - Title V	Intermediate	$2,863	$4,426	$8,574	$2,949	$2,949	$8,574	$4,512	$2,949	$8,574	$4,512	$2,949	$10,137	$63,967
3 - Title V	Peaking	$229	$354	$286	$236	$236	$286	$361	$236	$286	$361	$236	$411	$3,517
4 - Asbestos Fees	Base	$1,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,500
5 - Emission Monitoring	Base	$46,794	$46,067	$46,327	$46,236	$50,843	$46,325	$27,084	$26,286	$26,623	$26,532	$86,532	$27,489	$503,141
5 - Emission Monitoring	Intermediate	$9,459	$9,459	$9,533	$9,501	$9,501	$9,533	$9,501	$9,501	$9,533	$9,501	$9,501	$9,533	$114,057
5 - Emission Monitoring	Peaking	$197	$197	$17,594	$200	$200	$203	$200	$200	$203	$200	$200	$203	$19,796
6 - General Water Quality	Base	$85,065	$99,540	$144,151	$88,410	$83,478	$132,074	$85,959	$88,639	$126,580	$92,415	$104,866	$114,388	$1,245,562
6 - General Water Quality	Intermediate	$16,606	$16,019	$18,127	$16,127	$16,127	$19,066	$16,127	$16,127	$18,127	$16,127	$16,127	$18,114	$202,820
6 - General Water Quality	Peaking	$881	$881	$1,050	$890	$890	$1,125	$890	$890	$1,050	$890	$890	$1,050	$11,380
6 - General Water Quality	Transmission	$5,477	$5,477	$20,462	$17,640	$17,640	$17,640	$17,640	$20,462	$17,640	$17,640	$9,640	$5,640	$172,995
7 - Groundwater Contamination Investigation [1]	Base	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($34,003)	($408,036)
7 - Groundwater Contamination Investigation	Distribution	$193,405	$193,405	$211,088	$194,378	$194,378	$194,378	$194,378	$211,088	$194,378	$208,921	$208,921	$194,381	$2,393,099
7 - Groundwater Contamination Investigation	Transmission	$14,887	$14,887	$16,539	$14,977	$14,977	$19,319	$19,319	$23,051	$14,977	$14,977	$14,977	$14,974	$197,861
8 - State NPDES Administration	Base	$0	$0	$500	$0	$0	$0	$0	$0	$0	$0	$0	$23,000	$23,500
8 - State NPDES Administration	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,500	$11,500
10 - Env Auditing/Assessment	Base	$0	$0	$0	$0	$0	$730	$0	$0	$11,654	$11,654	$0	$0	$24,039
10 - Env Auditing/Assessment	Intermediate	$0	$0	$0	$0	$0	$250	$0	$0	$3,991	$3,991	$0	$0	$8,233
10 - Env Auditing/Assessment	Peaking	$0	$0	$0	$0	$0	$20	$0	$0	$319	$319	$0	$0	$659
11 - General Solid & Hazardous Waste [1]	Base	$7,107	$7,107	$24,246	$7,421	$7,421	$22,421	$7,421	$7,421	$22,421	$9,246	$7,421	$22,430	$152,086
11 - General Solid & Hazardous Waste	Distribution	$49,884	$49,884	$56,277	$50,234	$50,234	$50,234	$50,234	$56,277	$50,234	$50,234	$50,234	$50,257	$614,217
11 - General Solid & Hazardous Waste	Intermediate	$4,155	$4,155	$4,888	$4,263	$4,263	$4,263	$4,263	$4,263	$4,263	$4,888	$4,263	$4,263	$52,186
11 - General Solid & Hazardous Waste	Peaking	$332	$332	$391	$341	$341	$341	$341	$341	$341	$391	$341	$341	$4,175
12 - Above Ground Storage Tanks	Base	$5,116	$5,116	$10,269	$5,269	$5,269	$11,364	$5,269	$5,269	$20,269	$5,269	$5,269	$10,269	$94,018
12 - Above Ground Storage Tanks	Distribution	$0	$0	$4,990	$5,000	$0	$6,590	$5,000	$10,000	$4,990	$5,000	$5,000	$4,990	$51,560
12 - Above Ground Storage Tanks	Intermediate	$1,752	$1,752	$11,805	$26,805	$25,680	$2,180	$1,805	$1,805	$6,805	$6,805	$6,805	$1,805	$95,799
12 - Above Ground Storage Tanks	Peaking	$140	$140	$144	$144	$144	$174	$144	$144	$144	$144	$144	$144	$1,754
19 - FDEP NOx Reduction Agreement	Base	$32,603	$32,575	$32,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$97,678
20 - Air Quality Compliance Program	Base	$14,351,501	$1,114,602	$2,050,152	$542,372	$652,261	$767,373	$705,378	$693,622	$735,371	$821,454	$554,942	$683,987	$23,673,016
22 - Crist Water Conservation	Base	$0	$147,203	$16,500	$0	$11,500	$5,000	$11,500	$0	$16,500	$14,500	$31,000	$5,000	$258,703
23 - Coal Combustion Residual	Base	$142,007	$113,369	$152,004	$142,013	$92,067	$95,515	$93,292	$103,574	$106,971	$242,491	$247,077	$214,747	$1,745,127
24 - Smith Water Conservation	Intermediate	$7,000	$7,000	$10,750	$7,000	$7,000	$10,750	$3,000	$12,500	$16,250	$12,500	$12,500	$16,250	$122,500
NOx Allowances	Base	$24	$0	$0	$0	$262	$476	$523	$519	$375	$0	$0	$21	$2,201
SO_2 Allowances	Base	$131	$66	$114	$130	$118	$223	$244	$243	$178	$103	$20	$117	$1,687
	Total	$14,967,250	$1,866,711	$2,969,556	$1,174,695	$1,236,166	$1,416,637	$1,257,332	$1,283,793	$1,409,257	$1,574,012	$1,368,241	$1,440,257	$31,963,907

Notes:

(1) Includes adjustment to expenses approved in Order No. PSC-94-0044-FOF-EI, issued January 12, 1994.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

JANUARY 2021 THROUGH DECEMBER 2021
O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
O&M Project	Strata	Monthly Data	Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	12 CP Demand	Energy	NCP Demand
2 - Air Emission Fees	Base	$255,915	100.0000%	$255,915	$0	$255,915	$0
2 - Air Emission Fees	Intermediate	$14,926	97.5922%	$14,567	$0	$14,567	$0
2 - Air Emission Fees	Peaking	$8,389	76.0860%	$6,383	$0	$6,383	$0
3 - Title V	Base	$128,382	100.0000%	$128,382	$0	$128,382	$0
3 - Title V	Intermediate	$63,967	97.5922%	$62,426	$0	$62,426	$0
3 - Title V	Peaking	$3,517	76.0860%	$2,676	$0	$2,676	$0
4 - Asbestos Fees	Base	$1,500	100.0000%	$1,500	$1,500	$0	$0
5 - Emission Monitoring	Base	$503,141	100.0000%	$503,141	$0	$503,141	$0
5 - Emission Monitoring	Intermediate	$114,057	97.5922%	$111,311	$0	$111,311	$0
5 - Emission Monitoring	Peaking	$19,796	76.0860%	$15,062	$0	$15,062	$0
5 - Emission Monitoring	Base	$0	100.0000%	$0	$0	$0	$0
5 - Emission Monitoring	Intermediate	$0	97.5922%	$0	$0	$0	$0
6 - General Water Quality	Base	$1,245,562	100.0000%	$1,245,562	$1,245,562	$0	$0
6 - General Water Quality	Intermediate	$202,820	97.5922%	$197,936	$197,936	$0	$0
6 - General Water Quality	Peaking	$11,380	76.0860%	$8,658	$8,658	$0	$0
6 - General Water Quality	Transmission	$172,995	97.2343%	$168,211	$168,211	$0	$0
7 - Groundwater Contamination Investigation	Base	($408,036)	100.0000%	($408,036)	($408,036)	$0	$0
7 - Groundwater Contamination Investigation	Distribution	$2,393,099	98.1419%	$2,348,633	$0	$0	$2,348,633
7 - Groundwater Contamination Investigation	Transmission	$197,861	97.2343%	$192,389	$192,389	$0	$0
8 - State NPDES Administration	Base	$23,500	100.0000%	$23,500	$23,500	$0	$0
8 - State NPDES Administration	Intermediate	$11,500	97.5922%	$11,223	$11,223	$0	$0
10 - Env Auditing/Assessment	Base	$24,039	100.0000%	$24,039	$24,039	$0	$0
10 - Env Auditing/Assessment	Intermediate	$8,233	97.5922%	$8,034	$8,034	$0	$0
10 - Env Auditing/Assessment	Peaking	$659	76.0860%	$501	$501	$0	$0
11 - General Solid & Hazardous Waste	Base	$152,086	100.0000%	$152,086	$152,086	$0	$0
11 - General Solid & Hazardous Waste	Distribution	$614,217	98.1419%	$602,804	$0	$0	$602,804
11 - General Solid & Hazardous Waste	Intermediate	$52,186	97.5922%	$50,930	$50,930	$0	$0
11 - General Solid & Hazardous Waste	Peaking	$4,175	76.0860%	$3,177	$3,177	$0	$0
12 - Above Ground Storage Tanks	Base	$94,018	100.0000%	$94,018	$94,018	$0	$0
12 - Above Ground Storage Tanks	Distribution	$51,560	98.1419%	$50,602	$0	$0	$50,602
12 - Above Ground Storage Tanks	Intermediate	$95,799	97.5922%	$93,492	$93,492	$0	$0
12 - Above Ground Storage Tanks	Peaking	$1,754	76.0860%	$1,334	$1,334	$0	$0
19 - FDEP NOx Reduction Agreement	Base	$97,678	100.0000%	$97,678	$0	$97,678	$0
20 - Air Quality Compliance Program	Base	$23,673,016	100.0000%	$23,673,016	$0	$23,673,016	$0
22 - Crist Water Conservation	Base	$258,703	100.0000%	$258,703	$258,703	$0	$0
23 - Coal Combustion Residual	Base	$1,745,127	100.0000%	$1,745,127	$1,745,127	$0	$0
24 - Smith Water Conservation	Intermediate	$122,500	97.5922%	$119,550	$119,550	$0	$0
NOx Allowances	Base	$2,201	100.0000%	$2,201	$0	$2,201	$0
SO_2 Allowances	Base	$1,687	100.0000%	$1,687	$0	$1,687	$0
	Total	$31,963,907		$31,868,419	$3,991,935	$24,874,445	$3,002,039

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

FORM: 42-2P-2

JANUARY 2021 THROUGH DECEMBER 2021
O&M ACTIVITIES

RAD - ECRC - 42 - 2P	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2. Total of O&M Activities	$14,967,250	$1,866,711	$2,969,556	$1,174,695	$1,236,166	$1,416,637	$1,257,332	$1,283,793	$1,409,257	$1,574,012	$1,368,241	$1,440,257	$31,963,907
3. Recoverable Costs Jurisdictionalized on Energy - Base	$14,453,191	$1,220,011	$2,243,852	$611,126	$725,873	$838,611	$760,180	$743,059	$786,761	$875,039	$663,882	$740,435	$24,662,020
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$12,322	$13,885	$33,033	$12,450	$12,450	$18,107	$14,013	$12,450	$18,107	$14,013	$12,450	$19,669	$192,950
Recoverable Costs Jurisdictionalized on Energy - Peaking	$426	$551	$22,495	$4,210	$436	$489	$561	$436	$489	$561	$436	$614	$31,702
Recoverable Costs Jurisdictionalized on 12 CP Demand - Trans.	$20,363	$20,363	$37,001	$32,617	$32,617	$36,959	$36,959	$43,513	$32,617	$32,617	$24,617	$20,614	$370,856
Recoverable Costs Jurisdictionalized on 12 CP Demand - Base	$206,792	$338,332	$313,668	$209,110	$165,732	$233,101	$169,438	$170,900	$270,392	$341,572	$361,630	$355,831	$3,136,499
Recoverable Costs Jurisdictionalized on 12 CP Demand - Interm.	$29,513	$28,926	$45,569	$54,194	$53,069	$36,508	$25,194	$34,694	$49,435	$44,310	$39,694	$51,931	$493,037
Recoverable Costs Jurisdictionalized on 12 CP Demand - Peaking	$1,354	$1,354	$1,586	$1,376	$1,376	$1,661	$1,376	$1,376	$1,855	$1,745	$1,376	$1,536	$17,967
Recoverable Costs Jurisdictionalized on NCP Demand - Dist.	$243,290	$243,290	$272,355	$249,612	$244,612	$251,202	$249,612	$277,365	$249,602	$264,155	$264,155	$249,628	$3,058,876
4. Retail Production Energy Jurisdictional Factor - Base	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
Retail Production Energy Jurisdictional Factor - Intermediate	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	
Retail Production Energy Jurisdictional Factor - Peaking	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	
Retail Distribution Demand Jurisdictional Factor	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	
Retail Transmission Demand Jurisdictional Factor	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	
Retail Production Demand Jurisdictional Factor - Base	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
Retail Production Demand Jurisdictional Factor - Intermediate	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	
Retail Production Demand Jurisdictional Factor - Peaking	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	
5. Jurisdictional Recoverable Costs- Transmission	$19,800	$19,800	$35,977	$31,715	$31,715	$35,937	$35,937	$42,310	$31,715	$31,715	$23,936	$20,044	$360,599
Jurisdictional Recoverable Costs - Production - Base	$14,659,983	$1,558,343	$2,557,519	$820,236	$891,606	$1,071,712	$929,618	$913,959	$1,057,153	$1,216,611	$1,025,513	$1,096,266	$27,798,519
Jurisdictional Recoverable Costs - Production - Intermediate	$40,828	$41,780	$76,709	$65,040	$63,942	$53,300	$38,263	$46,009	$65,916	$56,919	$50,889	$69,876	$669,470
Jurisdictional Recoverable Costs - Production - Peaking	$1,354	$1,449	$18,322	$4,250	$1,378	$1,635	$1,473	$1,378	$1,783	$1,754	$1,378	$1,635	$37,791
Jurisdictional Recoverable Costs - Distribution	$238,769	$238,769	$267,294	$244,974	$240,067	$246,534	$244,974	$272,211	$244,964	$259,247	$259,247	$244,989	$3,002,039
6. Total Jurisdictional Recoverable Costs for O&M	$14,960,734	$1,860,141	$2,955,821	$1,166,215	$1,228,708	$1,409,118	$1,250,264	$1,275,867	$1,401,531	$1,566,246	$1,360,963	$1,432,811	$31,868,419

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

JANUARY 2021 THROUGH DECEMBER 2021
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

Capital Project	Strata	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1-Air Quality Assurance Testing	Base	$1,386	$1,381	$1,375	$1,369	$1,363	$1,358	$1,352	$1,346	$1,340	$1,335	$1,329	$1,323	$16,258
2-Crist 5, 6 & 7 Precipitator Projects	Base	$303,390	$302,747	$302,103	$301,460	$300,817	$300,173	$299,530	$298,887	$298,243	$297,600	$296,956	$296,313	$3,598,220
3-Crist 7 Flue Gas Conditioning	Base	$8,598	$8,598	$8,598	$8,598	$8,598	$8,598	$8,598	$8,598	$8,598	$8,598	$8,598	$8,598	$103,178
4-Low NOx Burners, Crist 6 & 7	Base	$141,637	$141,371	$141,105	$140,840	$140,574	$140,308	$140,043	$139,777	$139,511	$139,246	$138,980	$138,714	$1,682,106
5-CEMS - Plants Crist & Daniel	Base	$43,552	$43,465	$43,378	$43,291	$43,203	$43,116	$43,029	$42,942	$42,854	$42,767	$42,680	$42,593	$516,870
6-Substation Contamination Remediation	Distribution	$32,568	$32,537	$32,505	$32,474	$32,442	$32,411	$32,379	$32,348	$32,316	$32,285	$32,253	$32,623	$389,139
6-Substation Contamination Remediation	Transmission	$5,712	$5,724	$5,740	$5,725	$5,767	$5,813	$5,845	$5,876	$5,907	$5,995	$6,041	$6,344	$70,490
7-Raw Water Flowmeters Plants Crist & Smith	Base	$758	$755	$752	$749	$747	$744	$741	$738	$735	$732	$729	$727	$8,908
7-Raw Water Flowmeters Plants Crist & Smith	Intermediate	$274	$274	$274	$274	$274	$274	$274	$274	$274	$274	$274	$274	$3,290
8-Crist Cooling Tower Cell	Base	$3,050	$3,050	$3,050	$3,050	$3,050	$3,050	$3,050	$3,050	$3,050	$3,050	$3,050	$3,050	$36,605
9-Crist Dechlorination System	Base	$1,877	$1,869	$1,862	$1,855	$1,848	$1,840	$1,833	$1,826	$1,818	$1,811	$1,804	$1,797	$22,040
10-Crist Diesel Fuel Oil Remediation	Base	$92	$91	$91	$91	$90	$90	$89	$89	$89	$88	$88	$87	$1,075
11-Crist Bulk Tanker Second Containment	Base	$391	$389	$387	$385	$383	$381	$379	$377	$375	$373	$371	$369	$4,560
12-Crist IWW Sampling System	Base	$227	$226	$225	$224	$223	$222	$221	$219	$218	$217	$216	$215	$2,653
13-Sodium Injection System	Base	$1,705	$1,700	$1,694	$1,689	$1,683	$1,678	$1,672	$1,667	$1,662	$1,656	$1,651	$1,645	$20,102
14-Smith Stormwater Collection System	Intermediate	$13,363	$13,301	$13,239	$13,177	$13,115	$13,053	$12,991	$12,929	$12,867	$12,804	$12,742	$12,680	$156,261
15-Smith Waste Water Treatment Facility	Intermediate	$6,942	$6,928	$6,914	$6,899	$6,885	$6,870	$6,856	$6,841	$6,827	$6,812	$6,798	$6,783	$82,355
16-Daniel Ash Management Project	Base	$101,706	$101,492	$101,277	$101,063	$100,849	$100,635	$100,420	$100,206	$99,992	$99,778	$99,564	$99,349	$1,206,331
17-Smith Water Conservation	Intermediate	$190,772	$192,271	$193,990	$196,771	$200,882	$207,546	$217,642	$228,619	$239,646	$252,035	$265,634	$277,769	$2,663,576
19-Crist Ozone Attainment	Base	$844,446	$842,119	$839,793	$837,466	$835,140	$832,813	$830,487	$828,160	$825,834	$823,507	$821,181	$818,854	$9,979,802
20-SPCC Compliance	Base	$5,713	$5,695	$5,678	$5,660	$5,642	$5,625	$5,607	$5,590	$5,572	$5,554	$5,537	$5,519	$67,392
20-SPCC Compliance	General	$189	$188	$187	$186	$185	$185	$184	$183	$182	$181	$180	$179	$2,209
20-SPCC Compliance	Intermediate	$111	$111	$111	$110	$110	$110	$109	$109	$109	$108	$108	$108	$1,314
21-Crist Common FTIR Monitor	Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22-Precipitator Upgrades - CAM Compliance	Base	$89,293	$89,028	$88,762	$88,497	$88,231	$87,965	$87,700	$87,434	$87,168	$86,903	$86,637	$86,372	$1,053,990
24-Crist Water Conservation	Base	$141,388	$141,006	$140,624	$140,242	$139,860	$139,478	$139,096	$138,714	$138,332	$137,950	$137,568	$137,186	$1,671,438
25-Plant NPDES Permit Compliance	Base	$66,516	$66,337	$66,158	$65,979	$65,800	$65,621	$65,442	$65,262	$65,083	$64,904	$64,725	$64,546	$786,374
25-Plant NPDES Permit Compliance	Intermediate	$35,215	$35,130	$35,044	$34,959	$34,874	$34,789	$34,703	$34,618	$34,533	$34,447	$34,362	$34,277	$416,950
26-Air Quality Compliance Program	Base	$10,105,110	$10,107,292	$10,088,265	$10,082,310	$10,076,370	$10,057,807	$10,038,313	$10,017,147	$9,997,436	$9,979,538	$9,961,996	$9,944,372	$120,455,955
26-Air Quality Compliance Program	Peaking	$1,880	$1,873	$1,866	$1,859	$1,852	$1,845	$1,838	$1,831	$1,824	$1,817	$1,810	$1,804	$22,099
26-Air Quality Compliance Program	Transmission	$13,250	$13,168	$13,086	$13,004	$12,922	$12,840	$12,759	$12,677	$12,595	$12,513	$12,431	$12,349	$153,594
27-General Water Quality	Base	$74,791	$83,733	$91,942	$100,218	$109,382	$119,663	$124,917	$124,875	$124,833	$124,790	$124,748	$124,706	$1,328,597
28-Coal Combustion Residuals	Base	$589,839	$611,175	$638,456	$663,736	$683,772	$701,373	$718,226	$734,215	$750,204	$766,007	$781,157	$799,668	$8,437,829
28-Coal Combustion Residuals	Intermediate	$567,266	$568,414	$569,562	$570,710	$571,858	$573,006	$574,154	$575,302	$576,450	$577,598	$578,746	$579,894	$6,882,959
29-Steam Electric Effluent Limitations	Base	$56,371	$57,248	$58,125	$59,002	$59,878	$60,755	$61,632	$62,508	$63,385	$64,262	$65,139	$66,015	$734,321
30-316b Cooling Water Intake Structure	Intermediate	$33,859	$42,284	$42,186	$42,089	$41,991	$41,894	$41,796	$41,699	$41,601	$41,504	$41,407	$41,309	$493,620
Regulatory Asset Smith Units 1 & 2	Intermediate	$216,161	$215,481	$214,801	$214,121	$213,441	$212,761	$212,081	$211,401	$210,721	$210,041	$209,361	$208,681	$2,549,055
NOx Allowances	Base	$521	$520	$520	$520	$520	$518	$515	$512	$509	$508	$508	$508	$6,179
SO_2 Allowances	Base	$35,969	$35,969	$35,968	$35,967	$35,967	$35,966	$35,964	$35,963	$35,962	$35,961	$35,961	$35,960	$431,577
		$13,735,891	$13,774,940	$13,789,694	$13,816,620	$13,840,588	$13,853,172	$13,862,466	$13,864,808	$13,868,657	$13,875,552	$13,883,320	$13,893,562	$166,059,271

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

JANUARY 2021 THROUGH DECEMBER 2021
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Capital Project	Strata	Monthly Data	Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	12 CP Demand	NCP Demand
1-Air Quality Assurance Testing	Base	$16,258	100.0000%	$16,258	$1,251	$15,007	$0
2-Crist 5, 6 & 7 Precipitator Projects	Base	$3,598,220	100.0000%	$3,598,220	$276,786	$3,321,433	$0
3-Crist 7 Flue Gas Conditioning	Base	$103,178	100.0000%	$103,178	$7,937	$95,241	$0
4-Low NOx Burners, Crist 6 & 7	Base	$1,682,106	100.0000%	$1,682,106	$129,393	$1,552,713	$0
5-CEMS - Plants Crist & Daniel	Base	$516,870	100.0000%	$516,870	$39,759	$477,111	$0
6-Substation Contamination Remediation	Distribution	$389,139	98.1419%	$381,909	$0	$0	$381,909
6-Substation Contamination Remediation	Transmission	$70,490	97.2343%	$68,540	$5,272	$63,268	$0
7-Raw Water Flowmeters Plants Crist & Smith	Base	$8,908	100.0000%	$8,908	$685	$8,222	$0
7-Raw Water Flowmeters Plants Crist & Smith	Intermediate	$3,290	97.5922%	$3,211	$247	$2,964	$0
8-Crist Cooling Tower Cell	Base	$36,605	100.0000%	$36,605	$2,816	$33,789	$0
9-Crist Dechlorination System	Base	$22,040	100.0000%	$22,040	$1,695	$20,344	$0
10-Crist Diesel Fuel Oil Remediation	Base	$1,075	100.0000%	$1,075	$83	$992	$0
11-Crist Bulk Tanker Second Containment	Base	$4,560	100.0000%	$4,560	$351	$4,209	$0
12-Crist IWW Sampling System	Base	$2,653	100.0000%	$2,653	$204	$2,449	$0
13-Sodium Injection System	Base	$20,102	100.0000%	$20,102	$1,546	$18,556	$0
14-Smith Stormwater Collection System	Intermediate	$156,261	97.5922%	$152,499	$11,731	$140,768	$0
15-Smith Waste Water Treatment Facility	Intermediate	$82,355	97.5922%	$80,372	$6,182	$74,190	$0
16-Daniel Ash Management Project	Base	$1,206,331	100.0000%	$1,206,331	$92,795	$1,113,536	$0
17-Smith Water Conservation	Intermediate	$2,663,576	97.5922%	$2,599,443	$199,957	$2,399,486	$0
19-Crist Ozone Attainment	Base	$9,979,802	100.0000%	$9,979,802	$767,677	$9,212,125	$0
20-SPCC Compliance	Base	$67,392	100.0000%	$67,392	$5,184	$62,208	$0
20-SPCC Compliance	General	$2,209	96.9888%	$2,143	$165	$1,978	$0
20-SPCC Compliance	Intermediate	$1,314	97.5922%	$1,282	$99	$1,184	$0
21-Crist Common FTIR Monitor	Base	$0	100.0000%	$0	$0	$0	$0
22-Precipitator Upgrades - CAM Compliance	Base	$1,053,990	100.0000%	$1,053,990	$81,076	$972,913	$0
24-Crist Water Conservation	Base	$1,671,438	100.0000%	$1,671,438	$128,572	$1,542,866	$0
25-Plant NPDES Permit Compliance	Base	$786,374	100.0000%	$786,374	$60,490	$725,883	$0
25-Plant NPDES Permit Compliance	Intermediate	$416,950	97.5922%	$406,911	$31,301	$375,610	$0
26-Air Quality Compliance Program	Base	$120,455,955	100.0000%	$120,455,955	$9,265,843	$111,190,112	$0
26-Air Quality Compliance Program	Peaking	$22,099	76.0860%	$16,814	$1,293	$15,521	$0
26-Air Quality Compliance Program	Transmission	$153,594	97.2343%	$149,346	$11,488	$137,858	$0
27-General Water Quality	Base	$1,328,597	100.0000%	$1,328,597	$102,200	$1,226,398	$0
28-Coal Combustion Residuals	Base	$8,437,829	100.0000%	$8,437,829	$649,064	$7,788,765	$0
28-Coal Combustion Residuals	Intermediate	$6,882,959	97.5922%	$6,717,233	$516,710	$6,200,523	$0
29-Steam Electric Effluent Limitations	Base	$734,321	100.0000%	$734,321	$56,486	$677,834	$0
30-316b Cooling Water Intake Structure	Intermediate	$493,620	97.5922%	$481,734	$37,056	$444,678	$0
Regulatory Asset Smith Units 1 & 2	Intermediate	$2,549,055	97.5922%	$2,487,680	$191,360	$2,296,320	$0
NOx Allowances	Base	$6,179	100.0000%	$6,179	$475	$5,704	$0
SO2 Allowances	Base	$431,577	100.0000%	$431,577	$33,198	$398,379	$0
		$166,059,271		$165,721,477	$12,718,428	$152,621,140	$381,909

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

FORM: 42-3P-2

JANUARY 2021 THROUGH DECEMBER 2021
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
2. Total of Capital Investment Projects	$13,735,891	$13,774,940	$13,789,694	$13,816,620	$13,840,588	$13,853,172	$13,862,466	$13,864,808	$13,868,657	$13,875,552	$13,883,320	$13,893,562	$166,059,271
3. Recoverable Costs Jurisdictionalized on 12 CP Demand - Trans.	$18,962	$18,892	$18,826	$18,729	$18,690	$18,654	$18,603	$18,553	$18,502	$18,508	$18,472	$18,694	$224,084
Recoverable Costs Jurisdictionalized on 12 CP Demand - Base	$12,618,328	$12,647,257	$12,660,189	$12,684,261	$12,703,989	$12,709,776	$12,708,855	$12,700,102	$12,692,805	$12,687,136	$12,681,172	$12,678,488	$152,172,359
Recoverable Costs Jurisdictionalized on 12 CP Demand - Inter.	$1,063,965	$1,074,194	$1,076,121	$1,079,110	$1,083,430	$1,090,302	$1,100,607	$1,111,792	$1,123,027	$1,135,625	$1,149,432	$1,161,775	$13,249,380
Recoverable Costs Jurisdictionalized on 12 CP Demand - Peaking	$1,880	$1,873	$1,866	$1,859	$1,852	$1,845	$1,838	$1,831	$1,824	$1,817	$1,810	$1,804	$22,099
Recoverable Costs Jurisdicitionalized on 12 CP Demand - General	$189	$188	$187	$186	$185	$185	$184	$183	$182	$181	$180	$179	$2,209
Recoverable Costs Jurisdictionalized on NCP Demand - Dist.	$32,568	$32,537	$32,505	$32,474	$32,442	$32,411	$32,379	$32,348	$32,316	$32,285	$32,253	$32,623	$389,139
4. Retail Transmission Demand Jurisdictional Factor	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	97.2343%	
Retail Production Demand Jurisdictional Factor - Base	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	
Retail Production Demand Jurisdictional Factor - Intermediate	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	97.5922%	
Retail Production Demand Jurisdictional Factor - Peaking	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	76.0860%	
Retail Production Demand Jurisdictional Factor - General	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	96.9888%	
Retail Distribution Demand Jurisdictional Factor	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	98.1419%	
5. Jurisdictional Recoverable Costs - Transmission	$18,437	$18,369	$18,305	$18,211	$18,173	$18,138	$18,089	$18,040	$17,991	$17,997	$17,961	$18,177	$217,886
Jurisdictional Recoverable Costs - Production - Base	$12,618,328	$12,647,257	$12,660,189	$12,684,261	$12,703,989	$12,709,776	$12,708,855	$12,700,102	$12,692,805	$12,687,136	$12,681,172	$12,678,488	$152,172,359
Jurisdictional Recoverable Costs - Production - Intermediate	$1,038,347	$1,048,330	$1,050,211	$1,053,128	$1,057,343	$1,064,050	$1,074,107	$1,085,023	$1,095,987	$1,108,282	$1,121,756	$1,133,802	$12,930,366
Jurisdictional Recoverable Costs - Production - Peaking	$1,430	$1,425	$1,420	$1,414	$1,409	$1,404	$1,399	$1,393	$1,388	$1,383	$1,377	$1,372	$16,814
Jurisdictional Recoverable Costs - General	$183	$182	$182	$181	$180	$179	$178	$177	$176	$176	$175	$174	$2,143
Jurisdictional Recoverable Costs - Distribution	$31,963	$31,932	$31,901	$31,870	$31,839	$31,808	$31,777	$31,747	$31,716	$31,685	$31,654	$32,016	$381,909
6. Total Jurisdictional Recoverable Costs for Capital	$13,708,688	$13,747,496	$13,762,207	$13,789,066	$13,812,934	$13,825,355	$13,834,405	$13,836,481	$13,840,063	$13,846,657	$13,854,096	$13,864,029	$165,721,477

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
401-Air Quality Assurance Testing - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	83,954	
3	Less: Accumulated Depreciation (C)	(15,991)	(16,991)	(17,990)	(18,990)	(19,989)	(20,988)	(21,988)	(22,987)	(23,987)	(24,986)	(25,986)	(26,985)	(27,985)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	67,963	66,963	65,964	64,964	63,965	62,965	61,966	60,967	59,967	58,968	57,968	56,969	55,969	
6	Average Net Investment		67,463	66,464	65,464	64,465	63,465	62,466	61,466	60,467	59,467	58,468	57,468	56,469	
7	Return on Average Net Investment														
	a Equity Component (D)		337	332	327	322	317	312	307	302	297	292	287	282	3,711
	b Debt Component		50	49	49	48	47	46	46	45	44	43	43	42	553
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		999	999	999	999	999	999	999	999	999	999	999	999	11,993
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		1,386	1,381	1,375	1,369	1,363	1,358	1,352	1,346	1,340	1,335	1,329	1,323	16,258

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
402-Crist 5, 6 & 7 Precipitator Projects - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	33,657,087	
3	Less: Accumulated Depreciation (C)	(260,059)	(372,249)	(484,439)	(596,629)	(708,820)	(821,010)	(933,200)	(1,045,391)	(1,157,581)	(1,269,771)	(1,381,961)	(1,494,152)	(1,606,342)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	33,397,028	33,284,838	33,172,648	33,060,457	32,948,267	32,836,077	32,723,886	32,611,696	32,499,506	32,387,316	32,275,125	32,162,935	32,050,745	
6	Average Net Investment		33,340,933	33,228,743	33,116,552	33,004,362	32,892,172	32,779,982	32,667,791	32,555,601	32,443,411	32,331,220	32,219,030	32,106,840	
7	Return on Average Net Investment														
	a Equity Component (D)		166,401	165,842	165,282	164,722	164,162	163,602	163,042	162,482	161,922	161,362	160,802	160,242	1,959,862
	b Debt Component		24,798	24,715	24,632	24,548	24,465	24,381	24,298	24,214	24,131	24,047	23,964	23,881	292,074
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	112,190	1,346,283
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		303,390	302,747	302,103	301,460	300,817	300,173	299,530	298,887	298,243	297,600	296,956	296,313	3,598,220

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
403-Crist 7 Flue Gas Conditioning - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
6	Average Net Investment		1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
7	Return on Average Net Investment														
	a Equity Component (D)		7,483	7,483	7,483	7,483	7,483	7,483	7,483	7,483	7,483	7,483	7,483	7,483	89,796
	b Debt Component		1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115	13,382
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		8,598	8,598	8,598	8,598	8,598	8,598	8,598	8,598	8,598	8,598	8,598	8,598	103,178

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
404-Low NOx Burners, Crist 6 & 7 - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	13,527,932	
3	Less: Accumulated Depreciation (C)	3,115,359	3,069,034	3,022,708	2,976,383	2,930,058	2,883,732	2,837,407	2,791,082	2,744,756	2,698,431	2,652,106	2,605,780	2,559,455	
4	CWIP - Non Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2+3+4) (A)	16,643,291	16,596,965	16,550,640	16,504,315	16,457,989	16,411,664	16,365,339	16,319,013	16,272,688	16,226,363	16,180,037	16,133,712	16,087,387	
6	Average Net Investment		16,620,128	16,573,803	16,527,477	16,481,152	16,434,827	16,388,501	16,342,176	16,295,851	16,249,525	16,203,200	16,156,875	16,110,549	
7	Return on Average Net Investment														
	a Equity Component (D)		82,949	82,718	82,487	82,256	82,025	81,793	81,562	81,331	81,100	80,869	80,637	80,406	980,134
	b Debt Component		12,362	12,327	12,293	12,258	12,224	12,190	12,155	12,121	12,086	12,052	12,017	11,983	146,067
8	Investment Expenses														
	a Depreciation (E)		44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	44,614	535,367
	b Amortization (F)		1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	20,537
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		141,637	141,371	141,105	140,840	140,574	140,308	140,043	139,777	139,511	139,246	138,980	138,714	1,682,106

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
405-CEMS - Plants Crist & Daniel - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	4,712,783	
3	Less: Accumulated Depreciation (C)	83,961	68,745	53,528	38,311	23,095	7,878	(7,338)	(22,555)	(37,772)	(52,988)	(68,205)	(83,421)	(98,638)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	4,796,744	4,781,528	4,766,311	4,751,094	4,735,878	4,720,661	4,705,445	4,690,228	4,675,011	4,659,795	4,644,578	4,629,362	4,614,145	
6	Average Net Investment		4,789,136	4,773,919	4,758,703	4,743,486	4,728,270	4,713,053	4,697,836	4,682,620	4,667,403	4,652,186	4,636,970	4,621,753	
7	Return on Average Net Investment														
	a Equity Component (D)		23,902	23,826	23,750	23,674	23,598	23,522	23,446	23,371	23,295	23,219	23,143	23,067	281,813
	b Debt Component		3,562	3,551	3,539	3,528	3,517	3,505	3,494	3,483	3,472	3,460	3,449	3,438	41,998
8	Investment Expenses														
	a Depreciation (E)		15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	15,217	182,599
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		872	872	872	872	872	872	872	872	872	872	872	872	10,460
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		43,552	43,465	43,378	43,291	43,203	43,116	43,029	42,942	42,854	42,767	42,680	42,593	516,870

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
406-Substation Contamination Remediation - Distribution

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	307,630	307,630
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	3,383,667	3,383,667	3,383,667	3,383,667	3,383,667	3,383,667	3,383,667	3,383,667	3,383,667	3,383,667	3,383,667	3,383,667	3,691,297	
3	Less: Accumulated Depreciation (C)	1,033,339	1,027,850	1,022,361	1,016,871	1,011,382	1,005,892	1,000,403	994,913	989,424	983,935	978,445	972,956	967,064	
4	CWIP - Non Interest Bearing	307,630	307,630	307,630	307,630	307,630	307,630	307,630	307,630	307,630	307,630	307,630	307,630	0	
5	Net Investment (Lines 2+3+4) (A)	4,724,637	4,719,147	4,713,658	4,708,169	4,702,679	4,697,190	4,691,700	4,686,211	4,680,722	4,675,232	4,669,743	4,664,253	4,658,362	
6	Average Net Investment		4,721,892	4,716,403	4,710,913	4,705,424	4,699,935	4,694,445	4,688,956	4,683,466	4,677,977	4,672,487	4,666,998	4,661,308	
7	Return on Average Net Investment														
	a Equity Component (D)		23,567	23,539	23,512	23,484	23,457	23,430	23,402	23,375	23,347	23,320	23,293	23,264	280,989
	b Debt Component		3,512	3,508	3,504	3,500	3,496	3,492	3,488	3,483	3,479	3,475	3,471	3,467	41,875
8	Investment Expenses														
	a Depreciation (E)		5,489	5,489	5,489	5,489	5,489	5,489	5,489	5,489	5,489	5,489	5,489	5,891	66,275
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		32,568	32,537	32,505	32,474	32,442	32,411	32,379	32,348	32,316	32,285	32,253	32,623	389,139

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
406-Substation Contamination Remediation - Transmission

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	10,500	1,250	0	21,000	1,250	16,000	1,250	16,000	21,000	1,250	0	89,500
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	250,130	250,130
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	339,156	589,286	
3	Less: Accumulated Depreciation (C)	(50,529)	(53,674)	(56,819)	(59,963)	(63,108)	(66,252)	(69,397)	(72,541)	(75,686)	(78,830)	(81,975)	(85,119)	(88,582)	
4	CWIP - Non Interest Bearing	160,630	160,630	171,130	172,380	172,380	193,380	194,630	210,630	211,880	227,880	248,880	250,130	(0)	
5	Net Investment (Lines 2+3+4) (A)	449,256	446,111	453,467	451,572	448,428	466,283	464,389	477,244	475,350	488,205	506,061	504,166	500,703	
6	Average Net Investment		447,684	449,789	452,520	450,000	457,356	465,336	470,816	476,297	481,777	497,133	505,113	502,435	
7	Return on Average Net Investment														
	a Equity Component (D)		2,234	2,245	2,258	2,246	2,283	2,322	2,350	2,377	2,405	2,481	2,521	2,508	28,230
	b Debt Component		333	335	337	335	340	346	350	354	358	370	376	374	4,207
8	Investment Expenses														
	a Depreciation (E)		3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,463	38,053
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		5,712	5,724	5,740	5,725	5,767	5,813	5,845	5,876	5,907	5,995	6,041	6,344	70,490

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
407-Raw Water Well Flowmeters Plants Crist & Smith - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	149,950	
3	Less: Accumulated Depreciation (C)	(104,668)	(105,168)	(105,668)	(106,168)	(106,668)	(107,167)	(107,667)	(108,167)	(108,667)	(109,167)	(109,667)	(110,166)	(110,666)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	45,281	44,781	44,282	43,782	43,282	42,782	42,282	41,782	41,283	40,783	40,283	39,783	39,283	
6	Average Net Investment		45,031	44,532	44,032	43,532	43,032	42,532	42,032	41,533	41,033	40,533	40,033	39,533	
7	Return on Average Net Investment														
	a Equity Component (D)		225	222	220	217	215	212	210	207	205	202	200	197	2,532
	b Debt Component		33	33	33	32	32	32	31	31	31	30	30	29	377
8	Investment Expenses														
	a Depreciation (E)		500	500	500	500	500	500	500	500	500	500	500	500	5,998
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		758	755	752	749	747	744	741	738	735	732	729	727	8,908

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
407-Raw Water Well Flowmeters Plants Crist & Smith - Intermediate

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	
6	Average Net Investment		47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	47,811	
7	Return on Average Net Investment														
	a Equity Component (D)		239	239	239	239	239	239	239	239	239	239	239	239	2,863
	b Debt Component		36	36	36	36	36	36	36	36	36	36	36	36	427
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		274	274	274	274	274	274	274	274	274	274	274	274	3,290

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
408-Crist Cooling Tower Cell - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
6	Average Net Investment		531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	531,926	
7	Return on Average Net Investment														
	a Equity Component (D)		2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655	31,858
	b Debt Component		396	396	396	396	396	396	396	396	396	396	396	396	4,748
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	36,605

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
409-Crist Dechlorination System - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	380,697	
3	Less: Accumulated Depreciation (C)	(274,097)	(275,366)	(276,635)	(277,904)	(279,173)	(280,442)	(281,711)	(282,980)	(284,249)	(285,518)	(286,787)	(288,056)	(289,325)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	106,600	105,331	104,062	102,793	101,524	100,255	98,986	97,717	96,448	95,179	93,910	92,641	91,372	
6	Average Net Investment		105,966	104,697	103,428	102,159	100,890	99,621	98,352	97,083	95,814	94,545	93,276	92,007	
7	Return on Average Net Investment														
	a Equity Component (D)		529	523	516	510	504	497	491	485	478	472	466	459	5,928
	b Debt Component		79	78	77	76	75	74	73	72	71	70	69	68	883
8	Investment Expenses														
	a Depreciation (E)		1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	1,269	15,228
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		1,877	1,869	1,862	1,855	1,848	1,840	1,833	1,826	1,818	1,811	1,804	1,797	22,040

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
410-Crist Diesel Fuel Oil Remediation - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	20,968	
3	Less: Accumulated Depreciation (C)	(17,119)	(17,189)	(17,259)	(17,329)	(17,398)	(17,468)	(17,538)	(17,608)	(17,678)	(17,748)	(17,818)	(17,888)	(17,958)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	3,849	3,779	3,709	3,639	3,569	3,499	3,429	3,360	3,290	3,220	3,150	3,080	3,010	
6	Average Net Investment		3,814	3,744	3,674	3,604	3,534	3,464	3,394	3,325	3,255	3,185	3,115	3,045	
7	Return on Average Net Investment														
	a Equity Component (D)		19	19	18	18	18	17	17	17	16	16	16	15	205
	b Debt Component		3	3	3	3	3	3	3	2	2	2	2	2	31
8	Investment Expenses														
	a Depreciation (E)		70	70	70	70	70	70	70	70	70	70	70	70	839
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		92	91	91	91	90	90	89	89	89	88	88	87	1,075

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
411-Crist Bulk Tanker Unloading Second Containment - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(92,194)	(92,533)	(92,871)	(93,209)	(93,548)	(93,886)	(94,224)	(94,563)	(94,901)	(95,239)	(95,578)	(95,916)	(96,254)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	9,301	8,962	8,624	8,286	7,947	7,609	7,271	6,932	6,594	6,256	5,918	5,579	5,241	
6	Average Net Investment		9,132	8,793	8,455	8,117	7,778	7,440	7,102	6,763	6,425	6,087	5,748	5,410	
7	Return on Average Net Investment														
	a Equity Component (D)		46	44	42	41	39	37	35	34	32	30	29	27	435
	b Debt Component		7	7	6	6	6	6	5	5	5	5	4	4	65
8	Investment Expenses														
	a Depreciation (E)		338	338	338	338	338	338	338	338	338	338	338	338	4,060
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		391	389	387	385	383	381	379	377	375	373	371	369	4,560

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
412-Crist IWW Sampling System - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(54,405)	(54,603)	(54,802)	(55,000)	(55,199)	(55,397)	(55,596)	(55,794)	(55,993)	(56,191)	(56,390)	(56,588)	(56,787)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	5,138	4,939	4,741	4,542	4,344	4,146	3,947	3,749	3,550	3,352	3,153	2,955	2,756	
6	Average Net Investment		5,039	4,840	4,642	4,443	4,245	4,046	3,848	3,649	3,451	3,252	3,054	2,855	
7	Return on Average Net Investment														
	a Equity Component (D)		25	24	23	22	21	20	19	18	17	16	15	14	236
	b Debt Component		4	4	3	3	3	3	3	3	3	2	2	2	35
8	Investment Expenses														
	a Depreciation (E)		198	198	198	198	198	198	198	198	198	198	198	198	2,382
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		227	226	225	224	223	222	221	219	218	217	216	215	2,653

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
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RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
413-Sodium Injection System - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	284,622	
3	Less: Accumulated Depreciation (C)	(152,255)	(153,204)	(154,153)	(155,102)	(156,050)	(156,999)	(157,948)	(158,897)	(159,845)	(160,794)	(161,743)	(162,692)	(163,640)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	132,366	131,418	130,469	129,520	128,571	127,623	126,674	125,725	124,776	123,828	122,879	121,930	120,981	
6	Average Net Investment		131,892	130,943	129,994	129,046	128,097	127,148	126,200	125,251	124,302	123,353	122,405	121,456	
7	Return on Average Net Investment														
	a Equity Component (D)		658	654	649	644	639	635	630	625	620	616	611	606	7,587
	b Debt Component		98	97	97	96	95	95	94	93	92	92	91	90	1,131
8	Investment Expenses														
	a Depreciation (E)		949	949	949	949	949	949	949	949	949	949	949	949	11,385
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		1,705	1,700	1,694	1,689	1,683	1,678	1,672	1,667	1,662	1,656	1,651	1,645	20,102

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
414-Smith Stormwater Collection System - Intermediate

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	2,764,379	
3	Less: Accumulated Depreciation (C)	(2,316,721)	(2,327,548)	(2,338,375)	(2,349,202)	(2,360,030)	(2,370,857)	(2,381,684)	(2,392,511)	(2,403,338)	(2,414,165)	(2,424,992)	(2,435,820)	(2,446,647)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	447,658	436,831	426,003	415,176	404,349	393,522	382,695	371,868	361,040	350,213	339,386	328,559	317,732	
6	Average Net Investment		442,244	431,417	420,590	409,763	398,935	388,108	377,281	366,454	355,627	344,800	333,973	323,145	
7	Return on Average Net Investment														
	a Equity Component (D)		2,207	2,153	2,099	2,045	1,991	1,937	1,883	1,829	1,775	1,721	1,667	1,613	22,920
	b Debt Component		329	321	313	305	297	289	281	273	265	256	248	240	3,416
8	Investment Expenses														
	a Depreciation (E)		10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	10,827	129,926
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		13,363	13,301	13,239	13,177	13,115	13,053	12,991	12,929	12,867	12,804	12,742	12,680	156,261

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
415-Smith Waste Water Treatment Facility - Intermediate

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	643,620	
3	Less: Accumulated Depreciation (C)	128,665	126,144	123,623	121,103	118,582	116,061	113,540	111,019	108,498	105,977	103,457	100,936	98,415	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	772,285	769,764	767,243	764,722	762,201	759,680	757,160	754,639	752,118	749,597	747,076	744,555	742,035	
6	Average Net Investment		771,024	768,503	765,983	763,462	760,941	758,420	755,899	753,378	750,857	748,337	745,816	743,295	
7	Return on Average Net Investment														
	a Equity Component (D)		3,848	3,836	3,823	3,810	3,798	3,785	3,773	3,760	3,747	3,735	3,722	3,710	45,347
	b Debt Component		573	572	570	568	566	564	562	560	558	557	555	553	6,758
8	Investment Expenses														
	a Depreciation (E)		2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	30,250
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		6,942	6,928	6,914	6,899	6,885	6,870	6,856	6,841	6,827	6,812	6,798	6,783	82,355

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
416-Daniel Ash Management Project - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	14,939,561	
3	Less: Accumulated Depreciation (C)	(7,281,280)	(7,318,635)	(7,355,990)	(7,393,345)	(7,430,699)	(7,468,054)	(7,505,409)	(7,542,764)	(7,580,119)	(7,617,474)	(7,654,829)	(7,692,184)	(7,729,539)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	7,658,281	7,620,926	7,583,571	7,546,217	7,508,862	7,471,507	7,434,152	7,396,797	7,359,442	7,322,087	7,284,732	7,247,377	7,210,022	
6	Average Net Investment		7,639,604	7,602,249	7,564,894	7,527,539	7,490,184	7,452,829	7,415,474	7,378,119	7,340,764	7,303,410	7,266,055	7,228,700	
7	Return on Average Net Investment														
	a Equity Component (D)		38,129	37,942	37,756	37,569	37,383	37,196	37,010	36,823	36,637	36,451	36,264	36,078	445,238
	b Debt Component		5,682	5,654	5,627	5,599	5,571	5,543	5,516	5,488	5,460	5,432	5,404	5,377	66,353
8	Investment Expenses														
	a Depreciation (E)		37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	37,355	448,259
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	20,540	246,481
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		101,706	101,492	101,277	101,063	100,849	100,635	100,420	100,206	99,992	99,778	99,564	99,349	1,206,331

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
417-Smith Water Conservation - Intermediate

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		307,759	384,129	384,477	754,500	848,394	1,628,237	2,045,421	1,952,105	2,062,989	2,427,081	2,484,873	1,916,581	17,196,547
	b Clearings to Plant		0	0	0	0	0	24,481	0	0	0	0	0	0	24,481
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,590,761	21,615,242	21,615,242	21,615,242	21,615,242	21,615,242	21,615,242	21,615,242	
3	Less: Accumulated Depreciation (C)	(3,484,846)	(3,569,409)	(3,653,973)	(3,738,537)	(3,823,101)	(3,907,665)	(3,992,276)	(4,076,936)	(4,161,596)	(4,246,256)	(4,330,915)	(4,415,575)	(4,500,235)	
4	CWIP - Non Interest Bearing	302,767	610,526	994,655	1,379,132	2,133,632	2,982,026	4,585,783	6,631,204	8,583,309	10,646,298	13,073,379	15,558,252	17,474,833	
5	Net Investment (Lines 2+3+4) (A)	18,408,683	18,631,878	18,931,443	19,231,356	19,901,292	20,665,123	22,208,748	24,169,510	26,036,956	28,015,285	30,357,706	32,757,919	34,589,841	
6	Average Net Investment		18,520,280	18,781,660	19,081,400	19,566,324	20,283,207	21,436,936	23,189,129	25,103,233	27,026,120	29,186,496	31,557,813	33,673,880	
7	Return on Average Net Investment														
	a Equity Component (D)		92,433	93,737	95,233	97,654	101,232	106,990	115,735	125,288	134,885	145,667	157,502	168,063	1,434,419
	b Debt Component		13,775	13,970	14,192	14,553	15,086	15,944	17,248	18,671	20,102	21,708	23,472	25,046	213,769
8	Investment Expenses														
	a Depreciation (E)		84,564	84,564	84,564	84,564	84,564	84,612	84,660	84,660	84,660	84,660	84,660	84,660	1,015,389
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		190,772	192,271	193,990	196,771	200,882	207,546	217,642	228,619	239,646	252,035	265,634	277,769	2,663,576

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
419-Crist FDEP Agreement for Ozone Attainment - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	119,583,919	
3	Less: Accumulated Depreciation (C)	(43,319,375)	(43,725,065)	(44,130,755)	(44,536,445)	(44,942,135)	(45,347,824)	(45,753,514)	(46,159,204)	(46,564,894)	(46,970,584)	(47,376,273)	(47,781,963)	(48,187,653)	
4	CWIP - Non Interest Bearing	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	447,438	
5	Net Investment (Lines 2+3+4) (A)	76,711,982	76,306,292	75,900,602	75,494,912	75,089,222	74,683,533	74,277,843	73,872,153	73,466,463	73,060,773	72,655,084	72,249,394	71,843,704	
6	Average Net Investment		76,509,137	76,103,447	75,697,757	75,292,067	74,886,378	74,480,688	74,074,998	73,669,308	73,263,618	72,857,929	72,452,239	72,046,549	
7	Return on Average Net Investment														
	a Equity Component (D)		381,850	379,825	377,800	375,776	373,751	371,726	369,701	367,677	365,652	363,627	361,602	359,578	4,448,564
	b Debt Component		56,906	56,605	56,303	56,001	55,699	55,398	55,096	54,794	54,492	54,191	53,889	53,587	662,961
8	Investment Expenses														
	a Depreciation (E)		395,364	395,364	395,364	395,364	395,364	395,364	395,364	395,364	395,364	395,364	395,364	395,364	4,744,362
	b Amortization (F)		10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	10,326	123,915
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		844,446	842,119	839,793	837,466	835,140	832,813	830,487	828,160	825,834	823,507	821,181	818,854	9,979,802

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
420-SPCC Compliance - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	
3	Less: Accumulated Depreciation (C)	(456,795)	(459,861)	(462,927)	(465,994)	(469,060)	(472,126)	(475,192)	(478,258)	(481,324)	(484,390)	(487,456)	(490,522)	(493,589)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	463,040	459,974	456,908	453,842	450,776	447,710	444,644	441,578	438,511	435,445	432,379	429,313	426,247	
6	Average Net Investment		461,507	458,441	455,375	452,309	449,243	446,177	443,111	440,044	436,978	433,912	430,846	427,780	
7	Return on Average Net Investment														
	a Equity Component (D)		2,303	2,288	2,273	2,257	2,242	2,227	2,212	2,196	2,181	2,166	2,150	2,135	26,630
	b Debt Component		343	341	339	336	334	332	330	327	325	323	320	318	3,969
8	Investment Expenses														
	a Depreciation (E)		3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	36,793
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		5,713	5,695	5,678	5,660	5,642	5,625	5,607	5,590	5,572	5,554	5,537	5,519	67,392

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
420-SPCC Compliance - General

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	13,195	
3	Less: Accumulated Depreciation (C)	(7,540)	(7,697)	(7,854)	(8,011)	(8,168)	(8,325)	(8,482)	(8,639)	(8,796)	(8,954)	(9,111)	(9,268)	(9,425)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	5,655	5,498	5,341	5,184	5,026	4,869	4,712	4,555	4,398	4,241	4,084	3,927	3,770	
6	Average Net Investment		5,576	5,419	5,262	5,105	4,948	4,791	4,634	4,477	4,320	4,163	4,005	3,848	
7	Return on Average Net Investment														
	a Equity Component (D)		28	27	26	25	25	24	23	22	22	21	20	19	282
	b Debt Component		4	4	4	4	4	4	3	3	3	3	3	3	42
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		157	157	157	157	157	157	157	157	157	157	157	157	1,885
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		189	188	187	186	185	185	184	183	182	181	180	179	2,209

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
420-SPCC Compliance - Intermediate

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	14,895	
3	Less: Accumulated Depreciation (C)	(5,625)	(5,684)	(5,742)	(5,800)	(5,859)	(5,917)	(5,975)	(6,034)	(6,092)	(6,150)	(6,209)	(6,267)	(6,325)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	9,269	9,211	9,153	9,094	9,036	8,978	8,919	8,861	8,803	8,744	8,686	8,628	8,569	
6	Average Net Investment		9,240	9,182	9,123	9,065	9,007	8,948	8,890	8,832	8,773	8,715	8,657	8,598	
7	Return on Average Net Investment														
	a Equity Component (D)		46	46	46	45	45	45	44	44	44	43	43	43	534
	b Debt Component		7	7	7	7	7	7	7	7	7	6	6	6	80
8	Investment Expenses														
	a Depreciation (E)		58	58	58	58	58	58	58	58	58	58	58	58	700
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		111	111	111	110	110	110	109	109	109	108	108	108	1,314

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
421-Crist Common FTIR Monitor - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
422-Precipitator Upgrades for CAM Compliance - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	13,895,639	
3	Less: Accumulated Depreciation (C)	(6,378,683)	(6,425,001)	(6,471,320)	(6,517,639)	(6,563,958)	(6,610,277)	(6,656,595)	(6,702,914)	(6,749,233)	(6,795,552)	(6,841,870)	(6,888,189)	(6,934,508)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	7,516,956	7,470,637	7,424,319	7,378,000	7,331,681	7,285,362	7,239,043	7,192,725	7,146,406	7,100,087	7,053,768	7,007,449	6,961,131	
6	Average Net Investment		7,493,797	7,447,478	7,401,159	7,354,840	7,308,522	7,262,203	7,215,884	7,169,565	7,123,246	7,076,928	7,030,609	6,984,290	
7	Return on Average Net Investment														
	a Equity Component (D)		37,401	37,170	36,938	36,707	36,476	36,245	36,014	35,783	35,551	35,320	35,089	34,858	433,553
	b Debt Component		5,574	5,539	5,505	5,470	5,436	5,402	5,367	5,333	5,298	5,264	5,229	5,195	64,611
8	Investment Expenses														
	a Depreciation (E)		46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	46,319	555,825
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		89,293	89,028	88,762	88,497	88,231	87,965	87,700	87,434	87,168	86,903	86,637	86,372	1,053,990

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
424-Crist Water Conservation - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	19,983,662	
3	Less: Accumulated Depreciation (C)	(6,911,232)	(6,977,844)	(7,044,457)	(7,111,069)	(7,177,681)	(7,244,293)	(7,310,905)	(7,377,518)	(7,444,130)	(7,510,742)	(7,577,354)	(7,643,966)	(7,710,579)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	13,072,430	13,005,818	12,939,205	12,872,593	12,805,981	12,739,369	12,672,757	12,606,144	12,539,532	12,472,920	12,406,308	12,339,695	12,273,083	
6	Average Net Investment		13,039,124	12,972,511	12,905,899	12,839,287	12,772,675	12,706,063	12,639,450	12,572,838	12,506,226	12,439,614	12,373,002	12,306,389	
7	Return on Average Net Investment														
	a Equity Component (D)		65,077	64,745	64,412	64,080	63,747	63,415	63,082	62,750	62,417	62,085	61,752	61,420	758,982
	b Debt Component		9,698	9,649	9,599	9,550	9,500	9,451	9,401	9,351	9,302	9,252	9,203	9,153	113,110
8	Investment Expenses														
	a Depreciation (E)		66,612	66,612	66,612	66,612	66,612	66,612	66,612	66,612	66,612	66,612	66,612	66,612	799,347
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		141,388	141,006	140,624	140,242	139,860	139,478	139,096	138,714	138,332	137,950	137,568	137,186	1,671,438

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
425-Plant NPDES Permit Compliance Projects - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	9,372,327	9,372,327	9,372,327	9,372,327	9,372,327	9,372,327	9,372,327	9,372,327	9,372,327	9,372,327	9,372,327	9,372,327	9,372,327	
3	Less: Accumulated Depreciation (C)	(3,205,475)	(3,236,716)	(3,267,958)	(3,299,199)	(3,330,440)	(3,361,681)	(3,392,922)	(3,424,163)	(3,455,404)	(3,486,645)	(3,517,886)	(3,549,127)	(3,580,368)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	6,166,852	6,135,610	6,104,369	6,073,128	6,041,887	6,010,646	5,979,405	5,948,164	5,916,923	5,885,682	5,854,441	5,823,200	5,791,958	
6	Average Net Investment		6,151,231	6,119,990	6,088,749	6,057,508	6,026,267	5,995,026	5,963,784	5,932,543	5,901,302	5,870,061	5,838,820	5,807,579	
7	Return on Average Net Investment														
	a Equity Component (D)		30,700	30,544	30,388	30,232	30,077	29,921	29,765	29,609	29,453	29,297	29,141	28,985	358,112
	b Debt Component		4,575	4,552	4,529	4,505	4,482	4,459	4,436	4,413	4,389	4,366	4,343	4,320	53,369
8	Investment Expenses														
	a Depreciation (E)		31,241	31,241	31,241	31,241	31,241	31,241	31,241	31,241	31,241	31,241	31,241	31,241	374,893
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		66,516	66,337	66,158	65,979	65,800	65,621	65,442	65,262	65,083	64,904	64,725	64,546	786,374

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
425-Plant NPDES Permit Compliance Projects - Intermediate

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	3,798,266	
3	Less: Accumulated Depreciation (C)	(245,305)	(260,181)	(275,058)	(289,934)	(304,811)	(319,687)	(334,564)	(349,440)	(364,317)	(379,194)	(394,070)	(408,947)	(423,823)	
4	CWIP - Non Interest Bearing	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	1,056	
5	Net Investment (Lines 2+3+4) (A)	3,554,017	3,539,141	3,524,264	3,509,388	3,494,511	3,479,634	3,464,758	3,449,881	3,435,005	3,420,128	3,405,252	3,390,375	3,375,499	
6	Average Net Investment		3,546,579	3,531,702	3,516,826	3,501,949	3,487,073	3,472,196	3,457,320	3,442,443	3,427,567	3,412,690	3,397,813	3,382,937	
7	Return on Average Net Investment														
	a Equity Component (D)		17,701	17,626	17,552	17,478	17,404	17,329	17,255	17,181	17,107	17,032	16,958	16,884	207,507
	b Debt Component		2,638	2,627	2,616	2,605	2,594	2,583	2,572	2,560	2,549	2,538	2,527	2,516	30,924
8	Investment Expenses														
	a Depreciation (E)		14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	14,877	178,518
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		35,215	35,130	35,044	34,959	34,874	34,789	34,703	34,618	34,533	34,447	34,362	34,277	416,950

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
426-Air Quality Compliance Program - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		619,194	646,541	540,294	369,042	277,915	192,523	192,523	192,523	697,628	822,628	822,628	697,628	6,071,069
	b Clearings to Plant		0	0	0	8,705,770	682,093	1,323,864	192,523	192,523	197,628	197,628	197,628	421,208	12,110,866
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	1,343,509,188	1,343,509,188	1,343,509,188	1,343,509,188	1,352,214,957	1,352,897,051	1,354,220,915	1,354,413,438	1,354,605,961	1,354,803,589	1,355,001,218	1,355,198,846	1,355,620,054	
3	Less: Accumulated Depreciation (C)	(360,565,415)	(364,455,886)	(368,367,280)	(372,278,674)	(376,203,976)	(380,144,036)	(384,086,787)	(388,031,556)	(391,976,678)	(395,922,162)	(399,868,015)	(403,814,238)	(407,761,111)	
4	CWIP - Non Interest Bearing	8,139,797	8,758,991	9,405,532	9,945,827	1,609,099	1,204,920	73,580	73,580	73,580	573,580	1,198,580	1,823,580	2,100,000	
5	Net Investment (Lines 2+3+4) (A)	991,083,569	987,812,293	984,547,440	981,176,340	977,620,080	973,957,935	970,207,707	966,455,461	962,702,863	959,455,008	956,331,782	953,208,187	949,958,943	
6	Average Net Investment		989,447,931	986,179,866	982,861,890	979,398,210	975,789,007	972,082,821	968,331,584	964,579,162	961,078,935	957,893,395	954,769,985	951,583,565	
7	Return on Average Net Investment														
	a Equity Component (D)		4,938,241	4,921,931	4,905,371	4,888,084	4,870,071	4,851,574	4,832,851	4,814,123	4,796,654	4,780,755	4,765,167	4,749,264	58,114,086
	b Debt Component		735,936	733,505	731,038	728,461	725,777	723,020	720,230	717,439	714,836	712,466	710,143	707,773	8,660,625
8	Investment Expenses														
	a Depreciation (E)		3,869,547	3,890,471	3,890,471	3,904,379	3,919,136	3,921,827	3,923,846	3,924,199	3,924,560	3,924,930	3,925,300	3,925,949	46,944,615
	b Amortization (F)		20,923	20,923	20,923	20,923	20,923	20,923	20,923	20,923	20,923	20,923	20,923	20,923	251,081
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	540,462	6,485,548
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		10,105,110	10,107,292	10,088,265	10,082,310	10,076,370	10,057,807	10,038,313	10,017,147	9,997,436	9,979,538	9,961,996	9,944,372	120,455,955

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
426-Air Quality Compliance Program - Peaking

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	229,742	
3	Less: Accumulated Depreciation (C)	(111,700)	(112,906)	(114,113)	(115,319)	(116,525)	(117,731)	(118,937)	(120,143)	(121,349)	(122,555)	(123,762)	(124,968)	(126,174)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	118,041	116,835	115,629	114,423	113,217	112,011	110,805	109,598	108,392	107,186	105,980	104,774	103,568	
6	Average Net Investment		117,438	116,232	115,026	113,820	112,614	111,408	110,202	108,995	107,789	106,583	105,377	104,171	
7	Return on Average Net Investment														
	a Equity Component (D)		586	580	574	568	562	556	550	544	538	532	526	520	6,636
	b Debt Component		87	86	86	85	84	83	82	81	80	79	78	77	989
8	Investment Expenses														
	a Depreciation (E)		1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	1,206	14,474
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		1,880	1,873	1,866	1,859	1,852	1,845	1,838	1,831	1,824	1,817	1,810	1,804	22,099

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
426-Air Quality Compliance Program - Transmission

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	(171,274)	(185,546)	(199,819)	(214,092)	(228,365)	(242,638)	(256,910)	(271,183)	(285,456)	(299,729)	(314,002)	(328,274)	(342,547)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+3+4) (A)	(171,274)	(185,546)	(199,819)	(214,092)	(228,365)	(242,638)	(256,910)	(271,183)	(285,456)	(299,729)	(314,002)	(328,274)	(342,547)	
6	Average Net Investment		(178,410)	(192,683)	(206,956)	(221,228)	(235,501)	(249,774)	(264,047)	(278,320)	(292,592)	(306,865)	(321,138)	(335,411)	
7	Return on Average Net Investment														
	a Equity Component (D)		(890)	(962)	(1,033)	(1,104)	(1,175)	(1,247)	(1,318)	(1,389)	(1,460)	(1,532)	(1,603)	(1,674)	(15,387)
	b Debt Component		(133)	(143)	(154)	(165)	(175)	(186)	(196)	(207)	(218)	(228)	(239)	(249)	(2,293)
8	Investment Expenses														
	a Depreciation (E)		14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	14,273	171,274
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		13,250	13,168	13,086	13,004	12,922	12,840	12,759	12,677	12,595	12,513	12,431	12,349	153,594

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
427-General Water Quality - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	996,766	
3	Less: Accumulated Depreciation (C)	(89,664)	(92,987)	(96,309)	(99,632)	(102,954)	(106,277)	(109,599)	(112,922)	(116,244)	(119,567)	(122,890)	(126,212)	(129,535)	
4	CWIP - Non Interest Bearing	396,465	396,465	396,465	396,465	396,465	396,465	396,465	396,465	396,465	396,465	396,465	396,465	396,465	
5	Crist Closed Ash Landfill Reg Asset	8,839,289	10,534,653	11,964,320	13,404,188	14,857,401	16,606,564	18,449,658	18,445,628	18,441,597	18,437,567	18,433,537	18,429,507	18,425,477	
6	Net Investment (Lines 2 + 3 + 4) (A)	10,142,855	11,834,897	13,261,241	14,697,787	16,147,677	17,893,517	19,733,289	19,725,936	19,718,583	19,711,231	19,703,878	19,696,525	19,689,173	
6	Average Net Investment		10,988,876	12,548,069	13,979,514	15,422,732	17,020,597	18,813,403	19,729,612	19,722,260	19,714,907	19,707,554	19,700,202	19,692,849	
7	Return on Average Net Investment														
	a Equity Component (D)		54,844	62,626	69,770	76,973	84,948	93,896	98,469	98,432	98,395	98,359	98,322	98,285	1,033,320
	b Debt Component		8,173	9,333	10,398	11,471	12,660	13,993	14,675	14,669	14,664	14,658	14,653	14,647	153,994
8	Investment Expenses														
	a Depreciation (E)		3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	39,871
	b Amortization (F)		8,451	8,451	8,451	8,451	8,451	8,451	8,451	8,451	8,451	8,451	8,451	8,451	101,413
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		1,703,816	1,438,118	1,448,319	1,461,664	1,757,614	1,851,545	4,421	4,421	4,421	4,421	4,421	4,421	9,687,602
9	Total System Recoverable Expenses (H)		74,791	83,733	91,942	100,218	109,382	119,663	124,917	124,875	124,833	124,790	124,748	124,706	1,328,597

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Associated to Regulatory Asset
(H) Line 7 + 8 (a through d)

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
428-Coal Combustion Residuals - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		154,688	486,505	486,505	486,505	486,505	486,505	486,505	486,505	486,505	486,505	486,505	818,323	5,838,065
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		184,479	1,187,596	1,187,596	1,187,596	1,187,596	1,187,596	1,187,596	1,187,596	1,187,596	1,187,596	1,187,596	2,190,713	14,251,150
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	80,652,604	80,652,604	80,652,604	80,652,604	80,652,604	80,652,604	80,652,604	80,652,604	80,652,604	80,652,604	80,652,604	80,652,604	80,652,604	
3	Less: Accumulated Depreciation (C)	(30,151,577)	(30,115,728)	(29,076,762)	(28,037,796)	(26,998,830)	(25,959,864)	(24,920,898)	(23,881,932)	(22,842,966)	(21,804,000)	(20,765,034)	(19,726,069)	(17,683,986)	
4	CWIP - Non Interest Bearing	(20,225,461)	(20,070,774)	(19,584,268)	(19,097,763)	(18,611,257)	(18,124,752)	(17,638,246)	(17,151,741)	(16,665,236)	(16,178,730)	(15,692,225)	(15,205,719)	(14,387,396)	
	Ash Pond Closure Regulatory Asset	40,179,026	42,793,539	45,904,159	49,256,839	51,669,864	53,193,594	54,757,280	56,019,969	57,282,659	58,545,348	59,743,012	60,778,063	61,813,114	
5	Net Investment (Lines 2 + 3 + 4) (A)	70,454,591	73,259,641	77,895,733	82,773,884	86,712,380	89,761,581	92,850,739	95,638,900	98,427,060	101,215,221	103,938,357	106,498,879	110,394,336	
6	Average Net Investment		71,857,116	75,577,687	80,334,808	84,743,132	88,236,981	91,306,160	94,244,819	97,032,980	99,821,141	102,576,789	105,218,618	108,446,607	
7	Return on Average Net Investment														
	a Equity Component (D)		358,632	377,201	400,943	422,945	440,382	455,700	470,367	484,282	498,198	511,951	525,136	541,247	5,486,986
	b Debt Component		53,446	56,214	59,752	63,031	65,629	67,912	70,098	72,172	74,245	76,295	78,260	80,661	817,714
8	Investment Expenses														
	a Depreciation (E)		93,769	93,769	93,769	93,769	93,769	93,769	93,769	93,769	93,769	93,769	93,769	93,769	1,125,231
	b Amortization (F)		23,058	23,058	23,058	23,058	23,058	23,058	23,058	23,058	23,058	23,058	23,058	23,058	276,691
	c Dismantlement		54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	54,861	658,328
	d Property Taxes		6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	6,073	72,879
	e Other (G)		2,637,571	3,133,678	3,375,737	2,436,083	1,546,787	1,586,744	1,285,747	1,285,747	1,285,747	1,220,722	1,058,109	1,058,109	21,910,780
9	Total System Recoverable Expenses (H)		589,839	611,175	638,456	663,736	683,772	701,373	718,226	734,215	750,204	766,007	781,157	799,668	8,437,829

Notes:
(A) "Other" Includes Cost of Removal for Daniel 1&2 and Scherer Ash Ponds
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Associated to Regulatory Asset
(H) Line 7 + 8 (a through d)

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
428-Coal Combustion Residuals - Intermediate

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		358,148	358,148	358,148	358,148	358,148	358,148	358,148	358,148	358,148	358,148	358,148	358,148	4,297,777
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	2,601,638	
3	Less: Accumulated Depreciation (C)	(134,692)	(292,661)	(450,630)	(608,598)	(766,567)	(924,535)	(1,082,504)	(1,240,472)	(1,398,441)	(1,556,409)	(1,714,378)	(1,872,346)	(2,030,315)	
4	CWIP - Non Interest Bearing	68,805,184	69,163,333	69,521,481	69,879,629	70,237,777	70,595,925	70,954,073	71,312,221	71,670,369	72,028,517	72,386,665	72,744,813	73,102,961	
5	Net Investment (Lines 2 + 3 + 4) (A)	71,272,130	71,472,309	71,672,489	71,872,669	72,072,848	72,273,028	72,473,207	72,673,387	72,873,566	73,073,746	73,273,926	73,474,105	73,674,285	
6	Average Net Investment		71,372,220	71,572,399	71,772,579	71,972,758	72,172,938	72,373,117	72,573,297	72,773,477	72,973,656	73,173,836	73,374,015	73,574,195	
7	Return on Average Net Investment														
	a Equity Component (D)		356,212	357,211	358,210	359,209	360,208	361,207	362,206	363,206	364,205	365,204	366,203	367,202	4,340,483
	b Debt Component		53,086	53,234	53,383	53,532	53,681	53,830	53,979	54,128	54,277	54,426	54,574	54,723	646,853
8	Investment Expenses														
	a Depreciation (E)		157,969	157,969	157,969	157,969	157,969	157,969	157,969	157,969	157,969	157,969	157,969	157,969	1,895,622
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		567,266	568,414	569,562	570,710	571,858	573,006	574,154	575,302	576,450	577,598	578,746	579,894	6,882,959

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
429-Steam Electric Effluent Limitations Guidelines - Base

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		172,448	172,448	172,448	172,448	172,448	172,448	172,448	172,448	172,448	172,448	172,448	172,448	2,069,375
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	6,042,460	
3	Less: Accumulated Depreciation (C)	(645,095)	(664,660)	(684,224)	(703,789)	(723,353)	(742,918)	(762,482)	(782,047)	(801,611)	(821,176)	(840,740)	(860,305)	(879,869)	
4	CWIP - Non Interest Bearing	910,075	1,082,523	1,254,971	1,427,419	1,599,867	1,772,315	1,944,763	2,117,211	2,289,659	2,462,107	2,634,555	2,807,002	2,979,450	
5	Net Investment (Lines 2 + 3 + 4) (A)	6,307,440	6,460,323	6,613,207	6,766,090	6,918,974	7,071,857	7,224,741	7,377,624	7,530,508	7,683,391	7,836,274	7,989,158	8,142,041	
6	Average Net Investment		6,383,882	6,536,765	6,689,649	6,842,532	6,995,416	7,148,299	7,301,182	7,454,066	7,606,949	7,759,833	7,912,716	8,065,600	
7	Return on Average Net Investment														
	a Equity Component (D)		31,861	32,624	33,387	34,150	34,913	35,676	36,440	37,203	37,966	38,729	39,492	40,255	432,696
	b Debt Component		4,748	4,862	4,976	5,089	5,203	5,317	5,431	5,544	5,658	5,772	5,885	5,999	64,484
8	Investment Expenses														
	a Depreciation (E)		19,564	19,564	19,564	19,564	19,564	19,564	19,564	19,564	19,564	19,564	19,564	19,564	234,774
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		197	197	197	197	197	197	197	197	197	197	197	197	2,367
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		56,371	57,248	58,125	59,002	59,878	60,755	61,632	62,508	63,385	64,262	65,139	66,015	734,321

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
430-316b Cooling Water Intake Structure Regulation - Intermediate

	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	12 Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		4,339,172	0	0	0	0	0	0	0	0	0	0	0	4,339,172
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	4,339,172	4,339,172	4,339,172	4,339,172	4,339,172	4,339,172	4,339,172	4,339,172	4,339,172	4,339,172	4,339,172	4,339,172	
3	Less: Accumulated Depreciation (C)	87,586	79,088	62,093	45,098	28,103	11,108	(5,887)	(22,882)	(39,877)	(56,873)	(73,868)	(90,863)	(107,858)	
4	CWIP - Non Interest Bearing	4,339,172	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	4,426,757	4,418,260	4,401,265	4,384,270	4,367,274	4,350,279	4,333,284	4,316,289	4,299,294	4,282,299	4,265,304	4,248,309	4,231,314	
6	Average Net Investment		4,422,508	4,409,762	4,392,767	4,375,772	4,358,777	4,341,782	4,324,787	4,307,792	4,290,797	4,273,801	4,256,806	4,239,811	
7	Return on Average Net Investment														
	a Equity Component (D)		22,072	22,009	21,924	21,839	21,754	21,669	21,585	21,500	21,415	21,330	21,245	21,160	259,503
	b Debt Component		3,289	3,280	3,267	3,255	3,242	3,229	3,217	3,204	3,191	3,179	3,166	3,154	38,673
8	Investment Expenses														
	a Depreciation (E)		8,498	16,995	16,995	16,995	16,995	16,995	16,995	16,995	16,995	16,995	16,995	16,995	195,444
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (H)		33,859	42,284	42,186	42,089	41,991	41,894	41,796	41,699	41,601	41,504	41,407	41,309	493,620

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this program, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Applicable depreciation rate or rates.
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this program.
(H) Line 7 + 8

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
For Program: SO2 Allowances

Line	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	6,272,417	6,272,283	6,272,213	6,272,096	6,271,963	6,271,841	6,271,616	6,271,368	6,271,122	6,270,941	6,270,835	6,270,812	6,270,692	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(131)	(128)	(125)	(122)	(119)	(115)	(112)	(109)	(106)	(103)	(100)	(97)	(93)	
3	Total Working Capital Balance	6,272,286	6,272,155	6,272,088	6,271,974	6,271,844	6,271,726	6,271,503	6,271,259	6,271,016	6,270,838	6,270,735	6,270,716	6,270,599	
4	Average Net Working Capital Balance		6,272,220	6,272,121	6,272,031	6,271,909	6,271,785	6,271,615	6,271,381	6,271,138	6,270,927	6,270,787	6,270,726	6,270,657	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		31,304	31,304	31,303	31,303	31,302	31,301	31,300	31,299	31,298	31,297	31,297	31,296	375,602
	b Debt Component (Line 4 x Debt Component x 1/12)		4,665	4,665	4,665	4,665	4,665	4,665	4,665	4,664	4,664	4,664	4,664	4,664	55,975
6	Total Return Component (B)		35,969	35,969	35,968	35,967	35,967	35,966	35,964	35,963	35,962	35,961	35,961	35,960	431,577
7	Expenses														
	a Gains		(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(38)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		134	70	117	133	121	226	247	246	181	106	23	120	1,725
8	Net Expenses (C)		131	66	114	130	118	223	244	243	178	103	20	117	1,687
9	Total System Recoverable Expenses (Lines 6 + 8)		36,100	36,035	36,082	36,098	36,085	36,188	36,208	36,206	36,140	36,064	35,980	36,077	433,264

Notes:
(A) The approved ROE is 10.25%.
(B) Line 6 is reported on Schedule 3P.
(C) Line 8 is reported on Schedule 2P.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021

For Program: Annual Nox and Seasonal NOx Allowances

Line	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Working Capital														
	a FERC 158.1 Allowance Inventory	90,777	90,753	90,753	90,753	90,753	90,490	90,014	89,491	88,972	88,597	88,597	88,597	88,576	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	90,777	90,753	90,753	90,753	90,753	90,490	90,014	89,491	88,972	88,597	88,597	88,597	88,576	
4	Average Net Working Capital Balance		90,765	90,753	90,753	90,753	90,621	90,252	89,753	89,232	88,785	88,597	88,597	88,587	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		453	453	453	453	452	450	448	445	443	442	442	442	5,377
	b Debt Component (Line 4 x Debt Component x 1/12)		68	68	68	68	67	67	67	66	66	66	66	66	801
6	Total Return Component (B)		521	520	520	520	520	518	515	512	509	508	508	508	6,179
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c NOx Allowance Expense		24	0	0	0	262	476	523	519	375	0	0	21	2,201
8	Net Expenses (C)		24	0	0	0	262	476	523	519	375	0	0	21	2,201
9	Total System Recoverable Expenses (Lines 6 + 8)		545	521	520	520	782	994	1,038	1,031	884	508	508	529	8,380

Notes:
(A) The approved ROE is 10.25%.
(B) Line 6 is reported on Schedule 3P.
(C) Line 8 is reported on Schedule 2P.

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

FORM: 42-4P

JANUARY 2021 THROUGH DECEMBER 2021
Regulatory Asset Smith Units 1 & 2 - Intermediate

Line	Description	Beginning of Period Amount	Estimated January	Estimated February	Estimated March	Estimated April	Estimated May	Estimated June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Twelve Month Total
1	Regulatory Asset Balance 182.2 (B)	17,075,405	17,075,405	16,956,825	16,838,246	16,719,667	16,601,088	16,482,509	16,363,929	16,245,350	16,126,771	16,008,192	15,889,613	15,771,033	
2	Less Amortization (C)	0	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	(118,579)	
3	Net Regulatory Asset Balance (Lines 1 + 2) (A)	17,075,405	16,956,825	16,838,246	16,719,667	16,601,088	16,482,509	16,363,929	16,245,350	16,126,771	16,008,192	15,889,613	15,771,033	15,652,454	
4	Average Regulatory Asset Balance		17,016,115	16,897,536	16,778,957	16,660,377	16,541,798	16,423,219	16,304,640	16,186,061	16,067,481	15,948,902	15,830,323	15,711,744	
5	Return on Average Regulatory Asset Balance														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		84,926	84,334	83,742	83,150	82,559	81,967	81,375	80,783	80,191	79,599	79,008	78,416	980,050
	b Debt Component (Line 6 x Debt Component x 1/12)		12,656	12,568	12,480	12,392	12,304	12,215	12,127	12,039	11,951	11,863	11,774	11,686	146,055
6	Amortization Expense														
	a Recoverable Costs Allocated to Energy		118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	1,422,950
	b Other (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Jurisdictional Recoverable Costs (Lines 5 + 6)		216,161	215,481	214,801	214,121	213,441	212,761	212,081	211,401	210,721	210,041	209,361	208,681	2,549,055

Notes:
(A) End of period Regulatory Asset Balance.
(B) Beginning of period Regulatory Asset Balance.
(C) Regulatory Asset has a 15 year amortization period.
(D) The equity component has been grossed up for taxes. The approved ROE is 10.25%.
(E) Regulatory Asset has a 15 year amortization period.
(F) Description and reason for "Other" adjustments to regulatory asset.

Gulf Power Company **FORM 42-4P**
Environmental Cost Recovery Clause
2020-2021 Annual Capital Depreciation Schedule

Project	Function	Unit	Utility	DEPR RATE	TYPE	Sum of Dec-20	Sum of Dec-21
401-Air Quality Assurance Testing	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	Amort	83,954	83,954
401-Air Quality Assurance Testing Total						**83,954**	**83,954**
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	Depr	291,139	291,139
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depr	453,061	453,061
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depr	32,765,204	32,765,204
402-Crist 5, 6 & 7 Precipitator Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depr	147,682	147,682
402-Crist 5, 6 & 7 Precipitator Projects Total						**33,657,087**	**33,657,087**
403-Crist 7 Flue Gas Conditioning	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depr	-	-
403-Crist 7 Flue Gas Conditioning Total						**-**	**-**
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depr	131,183	131,183
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depr	3,912,618	3,912,618
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31400	4.00%	Depr	11,338	11,338
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depr	9,284,648	9,284,648
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31500	4.00%	Depr	44,385	44,385
404-Low NOx Burners, Crist 6 & 7	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	Amort	143,759	143,759
404-Low NOx Burners, Crist 6 & 7 Total						**13,527,932**	**13,527,932**
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	350,454	350,454
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depr	3,132,384	3,132,384
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depr	24,046	24,046
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depr	20,502	20,502
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depr	217,721	217,721
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depr	341,530	341,530
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	Depr	356,393	356,393
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL P-Com 1-2	31500	3.00%	Depr	196,553	196,553
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL P-Com 1-2	31670	14.29%	Depr	3,097	3,097
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31200	3.00%	Depr	32,584	32,584
405-CEMS - Plants Crist & Daniel	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31200	3.00%	Depr	37,519	37,519
405-CEMS - Plants Crist & Daniel Total						**4,712,783**	**4,712,783**
406-Substation Contamination Remediation	06 - Transmission Plant - Electric	G:Transmission Substations	35200	1.70%	Depr	339,156	339,156
406-Substation Contamination Remediation	07 - Distribution Plant - Electric	G:Distribution	36100	1.90%	Depr	587,654	587,654
406-Substation Contamination Remediation	07 - Distribution Plant - Electric	G:Distribution	36200	3.10%	Depr	2,796,013	3,353,773
406-Substation Contamination Remediation Total						**3,722,823**	**4,280,583**
407-Raw Water Well Flowmeters Plants Crist & Smith	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depr	149,950	149,950
407-Raw Water Well Flowmeters Plants Crist & Smith	05 - Other Generation Plant	G:Smith Common - CT and CC	34300	4.70%	Depr	-	-
407-Raw Water Well Flowmeters Plants Crist & Smith Total						**149,950**	**149,950**
408-Crist Cooling Tower Cell	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depr	-	-
408-Crist Cooling Tower Cell Total						**-**	**-**
409-Crist Dechlorination System	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	76,079	76,079
409-Crist Dechlorination System	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	Depr	304,619	304,619
409-Crist Dechlorination System Total						**380,697**	**380,697**
410-Crist Diesel Fuel Oil Remediation	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depr	20,968	20,968
410-Crist Diesel Fuel Oil Remediation Total						**20,968**	**20,968**
411-Crist Bulk Tanker Unloading Second Containment	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depr	101,495	101,495
411-Crist Bulk Tanker Unloading Second Containment Total						**101,495**	**101,495**
412-Crist IWW Sampling System	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	59,543	59,543
412-Crist IWW Sampling System Total						**59,543**	**59,543**
413-Sodium Injection System	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depr	284,622	284,622
413-Sodium Injection System Total						**284,622**	**284,622**
414-Smith Stormwater Collection System	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depr	2,601,079	2,601,079
414-Smith Stormwater Collection System	05 - Other Generation Plant	G:Smith Common - CT and CC	34500	4.70%	Depr	163,300	163,300
414-Smith Stormwater Collection System Total						**2,764,379**	**2,764,379**
415-Smith Waste Water Treatment Facility	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depr	643,620	643,620
415-Smith Waste Water Treatment Facility Total						**643,620**	**643,620**
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.00%	Depr	7,157,673	7,157,673
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	Depr	5,258,246	5,258,246
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-4	31200	3.00%	Depr	1,633	1,633
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL P-Com 1-4	31670	14.29%	Depr	639	639
416-Daniel Ash Management Project	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31500	3.00%	Depr	2,521,370	2,521,370
416-Daniel Ash Management Project Total						**14,939,561**	**14,939,561**
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depr	669,502	669,502
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Common - CT and CC	34500	4.70%	Depr	2,059,084	2,059,084
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Unit 3 - Combined Cycle	34100	4.70%	Depr	18,853,016	18,877,498
417-Smith Water Conservation	05 - Other Generation Plant	G:Smith Unit 3 - Combined Cycle	34500	4.70%	Depr	9,159	9,159
417-Smith Water Conservation Total						**21,590,761**	**21,615,242**
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	1,279,759	1,279,759
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depr	804,175	804,175
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	Amort	149,244	149,244
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depr	1,315,960	1,315,960
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depr	1,314,974	1,314,974
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31100	4.00%	Depr	2	2
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depr	7,598,952	7,598,952
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31500	4.00%	Depr	263,775	263,775
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depr	97,857,563	97,857,563
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31500	4.00%	Depr	8,173,896	8,173,896
419-Crist FDEP Agreement for Ozone Attainment	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	Amort	825,620	825,620

Gulf Power Company **FORM 42-4P**
Environmental Cost Recovery Clause
2020-2021 Annual Capital Depreciation Schedule

419-Crist FDEP Agreement for Ozone Attainment Total						**119,583,919**	**119,583,919**
420-SPCC Compliance	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	919,836	919,836
420-SPCC Compliance	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depr	14,895	14,895
420-SPCC Compliance	08 - General Plant	G:General Plant	39400	14.29%	Amort	13,195	13,195
420-SPCC Compliance Total						**947,925**	**947,925**
421-Crist Common FTIR Monitor	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	Depr	-	-
421-Crist Common FTIR Monitor Total						-	-
422-Precipitator Upgrades for CAM Compliance	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depr	6,832,729	6,832,729
422-Precipitator Upgrades for CAM Compliance	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depr	7,062,910	7,062,910
422-Precipitator Upgrades for CAM Compliance Total						**13,895,639**	**13,895,639**
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	127,481	127,481
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depr	6,593,728	6,593,728
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	Depr	8,510,363	8,510,363
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31500	4.00%	Depr	2,544,385	2,544,385
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	Depr	353,327	353,327
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depr	226,578	226,578
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depr	179,580	179,580
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depr	221,303	221,303
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31400	4.00%	Depr	857,763	857,763
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31500	4.00%	Depr	39,519	39,519
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depr	198,390	198,390
424-Crist Water Conservation	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31400	4.00%	Depr	131,244	131,244
424-Crist Water Conservation Total						**19,983,662**	**19,983,662**
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	325,432	325,432
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31400	4.00%	Depr	1,693,220	1,693,220
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31400	4.00%	Depr	1,085,261	1,085,261
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depr	440,705	440,705
425-Plant NPDES Permit Compliance Projects	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31400	4.00%	Depr	5,827,708	5,827,708
425-Plant NPDES Permit Compliance Projects	05 - Other Generation Plant	G:Smith Common - CT and CC	34400	4.70%	Depr	3,798,266	3,798,266
425-Plant NPDES Permit Compliance Projects Total						**13,170,593**	**13,170,593**
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	60,497,137	68,567,070
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31200	4.00%	Depr	401,805,855	402,104,808
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31400	4.00%	Depr	257,354	257,354
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31500	4.00%	Depr	79,991,591	79,991,591
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Common A	31600	4.00%	Amort	3,195,617	3,195,617
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31200	4.00%	Depr	4,983,840	5,217,140
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 4	31500	4.00%	Depr	2,015,231	2,015,231
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31200	4.00%	Depr	5,746,266	5,934,212
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 5	31500	4.00%	Depr	2,230,365	2,230,365
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31200	4.00%	Depr	148,099,768	148,099,768
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 6	31500	4.00%	Depr	25,120,806	25,120,806
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31200	4.00%	Depr	17,539,848	17,539,848
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31400	4.00%	Depr	27,706,471	27,706,471
426-Air Quality Compliance Program	02 - Steam Generation Plant	CRIST PLANT - Unit 7	31500	4.00%	Depr	2,126,229	2,126,229
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.00%	Depr	10,151,208	10,374,788
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31200	3.00%	Depr	210,352,874	210,352,874
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31500	3.00%	Depr	16,402,310	16,402,310
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31600	3.00%	Depr	334,923	334,923
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31650	20.00%	Depr	226,142	226,142
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL P-Com 1-2	31670	14.29%	Depr	377,947	383,892
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31100	3.00%	Depr	337,967	337,967
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31200	3.00%	Depr	94,573,715	94,917,893
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31500	3.00%	Depr	929,672	929,672
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31600	3.00%	Depr	151,046	151,046
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31200	3.00%	Depr	40,904,739	41,079,526
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31600	3.00%	Depr	(22,658)	(22,658)
426-Air Quality Compliance Program	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31670	14.29%	Depr	22,658	22,658
426-Air Quality Compliance Program	02 - Steam Generation Plant	G:Crist Plant	31670	14.29%	Amort	842,035	842,035
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31100	2.20%	Depr	798,405	798,405
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31200	2.20%	Depr	8,873,354	8,873,354
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31500	2.20%	Depr	854,675	854,675
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common A	31670	14.29%	Amort	20,761	20,761
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31100	2.20%	Depr	960,382	960,382
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31200	2.20%	Depr	13,347,491	13,347,491
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31500	2.20%	Depr	126,817	164,560
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31600	2.20%	Depr	553	553
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-Common B	31670	14.29%	Depr	85,069	85,069
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31100	2.20%	Depr	4,550,092	6,891,926
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31200	2.20%	Depr	145,003,255	145,195,921
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31500	2.20%	Depr	5,887,973	5,887,973
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31600	2.20%	Depr	612	612
426-Air Quality Compliance Program	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31670	14.29%	Depr	19,403	19,403
426-Air Quality Compliance Program	05 - Other Generation Plant	G:Smith Plant CT	34200	6.30%	Depr	229,742	229,742
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission 115-500KV Lines	35400	2.00%	Depr	565,062	565,062
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission 115-500KV Lines	35500	4.60%	Depr	502,662	502,662
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission 115-500KV Lines	35600	2.60%	Depr	576,009	576,009
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission Substations	35200	1.70%	Depr	211,336	211,336
426-Air Quality Compliance Program	06 - Transmission Plant - Electric	G:Transmission Substations	35300	2.80%	Depr	4,224,323	4,224,323
426-Air Quality Compliance Program Total						**1,343,738,929**	**1,355,849,796**
427-General Water Quality	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	996,766	996,766
427-General Water Quality Total						**996,766**	**996,766**

Gulf Power Company **FORM 42-4P**
Environmental Cost Recovery Clause
2020-2021 Annual Capital Depreciation Schedule

428-Coal Combustion Residuals	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	859,107	859,107
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL P-Com 1-2	31100	3.00%	Depr	710,331	710,331
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL PLANT - Unit 1	31200	3.00%	Depr	3,881,145	3,881,145
428-Coal Combustion Residuals	02 - Steam Generation Plant	DANIEL PLANT - Unit 2	31200	3.00%	Depr	5,570,478	5,570,478
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Crist Plant	31100	0.00%	Dismtl	-	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Daniel Plant	31100	0.00%	Dismtl	-	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	G:Scherer Plant	31100	0.00%	Dismtl	-	-
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common B	31000	0.00%	Land	773,371	773,371
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common B	31100	2.20%	Depr	14,365,061	14,365,061
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-Common B	31200	2.20%	Depr	9,868,352	9,868,352
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31100	2.20%	Depr	370,526	370,526
428-Coal Combustion Residuals	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31200	2.20%	Depr	6,523,486	6,523,486
428-Coal Combustion Residuals	05 - Other Generation Plant	G:Smith Common - CT and CC	34100	4.70%	Depr	39,165,682	39,165,682
428-Coal Combustion Residuals	05 - Other Generation Plant	G:Smith Common - CT and CC	34500	4.70%	Depr	1,011,135	1,011,135
428-Coal Combustion Residuals	05 - Other Generation Plant	G:Smith Common - CT and CC	34600	4.70%	Depr	155,569	155,569
428-Coal Combustion Residuals	08 - General Plant	G:General Plant	39000	2.00%	Depr	-	-
428-Coal Combustion Residuals Total						**83,254,241**	**83,254,241**
429-Steam Electric Effluent Limitations Guidelines	02 - Steam Generation Plant	CRIST PLANT - Common A	31100	4.00%	Depr	5,657,885	5,657,885
429-Steam Electric Effluent Limitations Guidelines	02 - Steam Generation Plant	SCHERER PLANT-Common B	31100	2.20%	Depr	-	-
429-Steam Electric Effluent Limitations Guidelines	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31100	2.20%	Depr	-	-
429-Steam Electric Effluent Limitations Guidelines	02 - Steam Generation Plant	SCHERER PLANT-UNIT #3	31200	2.20%	Depr	384,575	384,575
429-Steam Electric Effluent Limitations Guidelines Total						**6,042,460**	**6,042,460**
430-316b Cooling Water Intake Structure Regulation	05 - Other Generation Plant	G:Smith Common - CT and CC	34300	4.70%	Depr	-	4,339,172
430-316b Cooling Water Intake Structure Regulation Total						**-**	**4,339,172**
Grand Total						**1,698,254,307**	**1,715,286,585**

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Air Quality Assurance Testing

Project No. 1 (Capital)

Project Description:

The Air Quality Assurance Testing project includes the audit test trailer and associated support equipment used to conduct Relative Accuracy Test Audits (RATAs) on the Continuous Emission Monitoring Systems (CEMS) as required by the 1990 Clean Air Act Amendments (CAAA). The equipment provides Gulf with the accuracy and reliability needed to measure SO_2, NOx, and CO_2 and to further maintain compliance with CAAA requirements.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $17,141.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $16,258.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist 5, 6 & 7 Precipitator Projects

Project No. 2 (Capital)

Project Description:

The Plant Crist precipitator projects are necessary to improve particulate removal capabilities. The larger more efficient precipitators with increased collection areas improve particulate collection efficiency and have reduced particulate emissions. The upgraded Crist Unit 7 precipitator was placed in service in 2004 as part of the Florida Department of Environmental Protections (FDEP) NOx Reduction Agreement. The Plant Crist Unit 6 precipitator upgrade was placed in service in 2012.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $3,718,240.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $3,598,220.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist 7 Flue Gas Conditioning

Project No. 3 (Capital)

Project Description: This project covers equipment required for the injection of sulfur trioxide into the flue gas to enhance particulate removal and improve the collection characteristics of fly ash. Retirement of the Plant Crist Unit 7 flue gas conditioning system was completed in 2005.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $104,389.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $103,178.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Low NO_x Burners, Crist 6 & 7

Project No. 4 (Capital)

Project Description: Low NO_x burners are unique burners installed to decrease the NO_x emissions that are formed during the combustion process. The Crist low NOx burners and associated equipment were installed to meet the requirements of the 1990 CAAA. The Low

NO_x burner systems have proven effective in reducing NO_x emissions. The low NO_x burners on Crist Unit 7 were replaced in the 2003-2004 timeframe and the Crist Unit 6 burners were replaced in 2005. The Crist Unit 7 band gas canes on the Low NOx burners were upgraded with new retractable gas gun burning technology in 2016. Additional gas gun upgrades were installed in 2018.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There was no new activity in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $1,733,968.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $1,682,106.

GULF POWER COMPANY
PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: CEMS- Plants Crist & Daniel (Capital)
Continuous Emission Monitoring (O&M)
Project No. 5 (Capital and O&M)

Project Description: The Continuous Emission Monitoring (CEM) project includes dilution extraction emission monitors that measure the concentrations of sulfur dioxide (SO_2), carbon dioxide (CO_2) and nitrogen oxides (NO_x) in the flue gas. Opacity and flow monitors were also installed under this project. All CEM monitors were installed pursuant to the 1990 CAAA. The systems at both Gulf and Mississippi Power continue to successfully meet or exceed routine quality assurance/quality control (QA/QC) audits as required by the 1990 CAAA.

The Emission Monitoring project includes O&M expenses associated with the CEM systems as required by the 1990 CAAA. These expenses are incurred in response to EPA's requirements that Gulf perform Quality Assurance/Quality Control (QA/QC) testing for the CEM equipment, including Relative Accuracy Test Audits (RATAs) and linearity tests.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
Capital - There is no new activity scheduled in 2020.
O&M - There is no new activity scheduled in 2020.

Project Costs:
(January 1, 2020 to December 31, 2020)
Capital - Project revenue requirements are estimated to be $533,364.
O&M - Project costs are estimated to be $688,542.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $516,870.

O&M - Estimated project costs for the projection period are $636,994.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Substation Contamination Remediation (Capital)
Groundwater Contamination Investigation (O&M)

Project No. 6 (Capital) and 7 (O&M)

Project Description: The substation contamination remediation project includes costs associated with groundwater treatment systems installed to address impacts from past herbicide applications at various substation sites. Capital components of substation remediation projects are also included in this project. The treatment systems have proven effective in groundwater remediation.

The groundwater contamination investigation O&M project includes substation investigation and remediation activities required to determine possible environmental impacts to soil and groundwater from past herbicide applications at various substation sites. Once possible environmental impacts to groundwater and soil have been identified remedial activities and further compliance monitoring are initiated.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Capital - During 2020, Gulf began implementation of a pilot test at the Wewa substation site that will evaluate the feasibility of using chemical injection for groundwater remediation. If successful, the pilot test results will be used to design the full-scale implementation of this technology.

O&M - Activity includes excavations at Graceville and Pittman substations for impacted soils which will allow Gulf to request a release from further remedial actions or No Further Action (NFA), from FDEP. Gulf is also working toward meeting conditions for an NFA request for the Destin, Holmes Creek, Sunny Hills and Miller Ferry sites.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $415,526 which is $60,133, or 12.6% lower than previously projected. The variance is primarily attributed to the retirement of the Ft. Walton substation groundwater remediation system. The retirement balance was inadvertently omitted in 2019 causing an overstatement in the revenue requirement that carried forward in the 2020 Projection Filing. In addition, 2019 costs for construction of the new remediation system were lower than estimated, which impacted the revenue requirement in 2020.

O&M - Project costs are estimated to be $2,091,013.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - During the first half of 2021, Gulf plans to continue the Wewa substation groundwater remediation pilot test. Once completed, a remedial action plan will be prepared and submitted to FDEP for review and approval. Estimated project revenue requirements for the projection period are $459,629.

O&M - Estimated project costs for the projection period are $2,182,924.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Raw Water Flowmeters - Plant Crist and Smith

Project No. 7 (Capital)

Project Description: The raw water flow meters' project was necessary for Gulf to comply with the Plant Crist and Plant Smith Consumptive Use and Individual Water Use permits, issued by the Northwest Florida Water Management District (NWFWMD). The Consumptive Use permits require the installation and monitoring of in-line totaling water flow meters on all existing and future water supply wells. The raw water flow meters have been installed at Plant Crist and Plant Smith.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $12,688.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $12,198.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist Cooling Tower Cell

Project No. 8 (Capital)

Project Description: The Crist cooling tower is a pollution control device which allows condenser cooling water to be continually reinjected into the condenser. The cooling tower reduces water discharge temperatures in order to meet the National Pollution Discharge Elimination System (NPDES) Industrial Wastewater (IWW) permit requirements. Plant Crist has maintained compliance with the temperature discharge limits as required by the facility's NPDES IWW permit. The original Unit 7 cooling tower cell was retired in 2007 when the new cooling tower was placed-in-service as part of the Crist scrubber project that is reflected in Air Quality Compliance Program.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $37,035.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $36,605.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist Dechlorination System

Project No. 9 (Capital)

Project Description: NPDES wastewater permits require reductions in chlorine concentrations prior to discharge from the plant. The Crist dechlorination system uses sodium bisulfite to chemically eliminate the residual chlorine present in the plant industrial wastewater prior to discharge. The system has been effective in maintaining chlorine discharge limits.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $23,178.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $22,040.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist Diesel Fuel Oil Remediation

Project No. 10 (Capital)

Project Description: The Plant Crist diesel fuel oil remediation project included installation of monitoring wells in the vicinity of the Crist diesel tank system. The project also included the installation of an impervious cap to reduce migration of contaminants to groundwater as required by FDEP.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $194.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $1,075.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist Bulk Tanker Unloading Secondary Containment

Project No. 11 (Capital)

Project Description: The Crist bulk tanker unloading secondary containment project was necessary to minimize the potential risk of an uncontrolled discharge of pollutants into the waters of the United States. Secondary containment was installed for tank unloading racks pursuant to the Federal Spill Prevention Control and Countermeasures (SPCC) regulation (40 CFR Part 112).

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $4,848.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $4,560.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist IWW Sampling System

Project No. 12 (Capital)

Project Description: The 1993 revision to Plant Crist's NPDES IWW permit moved the discharge compliance point from the end of the discharge canal to a point upstream of Thompson's Bayou. To allow for this sample point modification, an access dock was constructed in the discharge canal. The Crist IWW project also included a small building for monitoring and sampling equipment. The dock is complete and samples are being collected at the required compliance point.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $2,822.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $2,653.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Sodium Injection System

Project No. 13 (Capital)

Project Description: The sodium injection project includes silo storage systems and associated components which inject sodium carbonate directly onto the coal feeder belt to enhance precipitator performance when burning low sulfur coal. Sodium injection was used at Plant Smith for Unit 1 and 2, and is used at Plant Crist for Unit 4 and 5 as needed. The injection of sodium carbonate as an additive to low sulfur coal reduces opacity levels in order to maintain compliance with the Clean Air Act provisions. The Smith Sodium Injection system was retired in 2016 after the coal units ceased operations.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Capital - There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $20,996.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $20,102.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Smith Stormwater Collection System

Project No. 14 (Capital)

Project Description: The NPDES stormwater program requires industrial facilities to install stormwater management systems in order to prevent the discharge of impacted stormwater to the surface waters of the United States. The Plant Smith stormwater sump system has been effective in managing onsite stormwater.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $165,602.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $156,261.

GULF POWER COMPANY
PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Smith Waste Water Treatment Facility
Project No. 15 (Capital)

Project Description: During the 1990s a domestic wastewater treatment facility was installed at Plant Smith to replace the septic tank system that was originally installed in the early 1960s. In 2004 a new wastewater treatment facility was installed to replace the facility installed in the 1990's. The new treatment plant included aeration and chlorination of the wastewater prior to discharge in the Plant Smith ash pond. Following retirement of the coal-fired units and associated staffing reductions, a new wastewater treatment facility with lower capacity was installed. Plant Smith has maintained compliance with the domestic wastewater treatment requirements in the NPDES IWW permit.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
Plant Smith incurred costs in 2020 to finalize installation of the new domestic wastewater treatment system.

Project Costs:
(January 1, 2020 to December 31, 2020)
Project revenue requirements are estimated to be $69,378.

Project Projections:

(January 1, 2021 to December 31, 2021)
Estimated project revenue requirements for the projection period are $82,355.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Daniel Ash Management Project

Project No. 16 (Capital)

Project Description: The original Daniel ash management project included the installation of a dry fly ash transport system, lining for the bottom of the ash pond, closure and capping of the existing fly ash pond, as well as expansion of the landfill area. In 2006, Plant Daniel completed construction of a new on-site ash storage facility in preparation for the completion and closure of the existing landfill area. Portions of the original Daniel ash storage facility were closed in place during 2010.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $1,243,496.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $1,206,331.

GULF POWER COMPANY
PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Smith Water Conservation
Project No. 17 (Capital) and 24 (O&M)

Project Description: Specific Condition 11 of Plant Smith's consumptive use permit, issued by the NWFWMD, requires the plant to implement measures to increase water conservation and efficiency at the facility. Phase I of the Smith Water Conservation project consisted of adding pumps, piping, valves, and controls to reclaim water from the ash pond. During Phase II of the project, the Smith closed loop cooling for the laboratory sampling system was installed to further reduce groundwater usage. Phase III of the project includes investigating and installing a deep injection well system to allow Plant Smith to utilize reclaimed water. Gulf has installed three deep injection wells, piping, and initial equipment needed for the reclaimed water pump station and for current wastewater discharges.

The Smith Water Conservation O&M project includes general maintenance expenses, sampling and analytical charges, and mechanical integrity testing required by the FDEP permit.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
Capital - During 2020 Gulf is continuing contract negotiations with reclaimed water providers and finalizing the project design and technical specifications.
O&M - Required maintenance and compliance monitoring are ongoing as required.

Project Costs:
(January 1, 2020 to December 31, 2020)
Capital - Project revenue requirements are estimated to be $2,304,613, which is $849,203 or 26.9% lower than previously projected. The variance is primarily due to postponing construction of the Plant Smith Underground Injection Control ("UIC") wastewater treatment system and its associated pump station from the Fall of 2020 to early 2021 due to additional time required to finalize the reclaimed water supply contract negotiations. The

new treatment system and permanent pump station are required to begin using reclaimed water for Unit 3's cooling tower water supply. Gulf has completed installation of three deep injection wells, piping, and initial equipment needed for the reclaimed water pump station.

O&M - Projected costs are estimated to be $36,806.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Plant Smith plans to begin construction of the new reclaimed water treatment system and permanent pump station in 2021. Both projects are required before the plant can begin using reclaimed water for the Unit 3 cooling tower water supply. Estimated project revenue requirements for the projection period are $2,663,576.

O&M - Estimated project costs for the projection period are $122,500.

GULF POWER COMPANY
PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist FDEP Agreement for Ozone Attainment (Capital)
FDEP NOx Reduction Agreement (O&M)
Project No. 19 (Capital and O&M)

Project Description: The Florida Department of Environmental Protection (FDEP) and Gulf Power entered into an agreement on August 28, 2002 to support Escambia/Santa Rosa County area's effort to maintain compliance with the 8-hour ozone ambient air quality standards. This agreement included a requirement for Gulf to install Selective Catalytic Reduction (SCR) controls on Plant Crist Unit 7, relocate the Crist Unit 7 precipitator, and install a NO_x reduction technology on Plant Crist Unit 6, and if necessary, Units 4 and 5. The O&M costs associated with this project includes anhydrous ammonia, air monitoring, catalyst regeneration, and general operation and maintenance expenses.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
Capital - During early 2020, costs were incurred for completion of the Unit 7 simulator controls replacement project. The controls for the low NOx burners and Unit 7 simulator were replaced in late 2019 because the supplier will be discontinuing support and updates for the controls later this year. To maintain cyber security, the control systems need to be up to date with supported operating systems to prevent and address cyber vulnerabilities.

O&M - The Crist Unit 7 SCR and Unit 4 and 5 Selective Non-Catalytic Reduction (SNCR) have ensured compliance with applicable regulations.

Project Costs:
(January 1, 2020 to December 31, 2020)
Capital - Project revenue requirements are estimated to be $10,386,786.
O&M - Project expenditures are estimated to be $227,320, which is $333,411 or 59.5% lower than previously projected. The variance is primarily due to maintenance costs associated with the Crist Unit 7 SCR project being less than originally projected.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - During 2021 Plant Crist plans to close the anhydrous ammonia tanks that were installed for the Unit 7 SCR project. The Unit 7 SCR is not expected to be required after the unit discontinues coal-fired operations. Estimated project revenue requirements for the projection period are $9,979,802.

O&M - Estimated project costs for the projection period are $97,678.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: SPCC Compliance

Project No. 20 (Capital)

Project Description: The SPCC compliance projects were required as the result of a more stringent July 2002 revision to Title 40 Code of Federal Regulation Part 112, which is commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. The 2002 regulatory revision specifically included oil-containing electrical equipment within the scope of the regulation. Therefore, oil-filled electrical equipment that has the potential to discharge to navigable waters must be provided with appropriate containment and/or diversionary structures to prevent such a discharge. The 2002 revisions also resulted in oil storage containers having a capacity greater than or equal to 55 gallons classified as bulk storage containers which are subject to the secondary containment requirements in 40 CFR Part 112.8(c).

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $74,023.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $70,915.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist Common FTIR Monitor

Project No. 21 (Capital)

Project Description: The purchase of a Fourier Transform Infrared (FTIR) spectrometer, a device used to measure and analyze various low concentration stack gas emissions, was required at Plant Crist under Title V regulations. Purchasing the FTIR instrument has enabled Gulf Power to measure ammonia slip emissions as required by the Plant Crist air permit.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $(860).

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $0.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Precipitator Upgrades for Compliance Assurance Monitoring

Project No. 22 (Capital)

Project Description: Compliance assurance monitoring ("CAM") precipitator upgrades were required to comply with new CAM regulations incorporated into Gulf's Title V permits in the 2005 time frame. CAM requirements are regulated under Title V of the 1990 CAAA, which requires a method of continuously monitoring particulate emissions. Opacity can be used as a surrogate parameter if the precipitator demonstrates a correlation between opacity and particulate matter. Gulf demonstrated this correlation by stack testing in 2003 and 2004, and the results were included as part of the CAM plans in Gulf's Title V air permits effective January 2005. Several precipitator upgrades have been necessary to meet the more stringent surrogate opacity standards under CAM.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

There is no new activity scheduled in 2020.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project revenue requirements are estimated to be $1,098,475.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $1,053,990.

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PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Crist Water Conservation
Project No. 24 (Capital) and 22 (O&M)

Project Description:
The goal of the Plant Crist water conservation and consumptive use efficiency project is to reduce the demand for groundwater and surface water withdrawals. Specific Condition 19 of the NWFWMD Individual Water Use Permit Number No.19850074 requires Plant Crist to implement measures to increase water conservation and efficiency at the facility. The first Plant Crist water conservation project included installing automatic level controls on the fire water tanks in order to reduce groundwater usage. The second phase of the project involved utilizing reclaimed water to reduce the demand for groundwater and surface water withdrawals at Plant Crist. Gulf began receiving reclaimed water in November 2010. Gulf also installed defoaming and acid injection systems for the Units 6 and 7 cooling towers to treat scaling and foam associated with reclaimed water usage.

The O&M project includes general expenses associated with the Plant Crist reclaimed water system such as chemical costs as well as piping, pump, and valve maintenance.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
Capital - There is no new activity scheduled in 2020.

O&M - Plant Crist has replaced two sections of acid line piping for cooling tower water treatment associated with reclaimed water usage.

Project Costs:
(January 1, 2020 to December 31, 2020)
Capital - Project revenue requirements are estimated to be $1,723,370.
O&M - Project expenditures are estimated to be $208,487, which is $162,508 or 353.4% higher than previously projected. The variance is due to chemical and maintenance costs

associated with Plant Crist's reclaimed water system being greater than originally projected. These costs are associated with replacing the reclaimed water line air relief valves, dispersant tank, as well as acid lines, which were originally scheduled to be replaced during the Fall of 2019.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $1,671,438.

O&M - Estimated project costs for the projection period are $258,703.

GULF POWER COMPANY
PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Plant NPDES Permit Compliance
Project No. 25 (Capital)

Project Description: The water quality based copper effluent limitations included in Chapter 62 Part 302, Florida Administrative Code (F.A.C.) were amended in 2002. The more stringent hardness-based standard is included by reference in the Plant Crist NPDES IWW permit.

Plant Crist installed stainless steel condenser tubes on Unit 6 during 2006 in an effort to meet the revised water quality standards during times of lower hardness in the river water. Plant Crist completed the second phase of the project in the 2008-2010 timeframe, which involved installing a chemical treatment and aeration system in the IWW treatment pond. Due to copper exceedances in the 2017 timeframe Gulf Power submitted results of a copper study to FDEP in June 2019 that recommended retubing the Unit 6C service water cooler and Units 4 and 5 condensers with stainless steel tubes to eliminate these copper sources. In 2019, Plant Crist completed retubing the 6C service water cooler and began the design and procurement process for replacing the Units 4-5 condenser tubes.

In 2019, Plant Smith completed replacement of the second discharge canal crossover to allow for continued safe access for obtaining representative main plant discharge samples as required by the Plant Smith NPDES IWW permit.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
The Crist unit 4&5 condenser tube replacement project was completed in May 2020.

Project Costs:
(January 1, 2020 to December 31, 2020)
Project revenue requirements are estimated to be $1,112,903.

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FORM: 42-5P

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project revenue requirements for the projection period are $1,203,324.

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PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Air Quality Compliance Program
Project No. 26 (Capital) and 20 (O&M)

Project Description: This project covers the prudently incurred costs for compliance with Gulf's Air Quality Compliance Program including the expenses associated with the Crist scrubber, SNCRs, and SCRs, the Daniel scrubber and injections systems, as well as air controls for Gulf's ownership portion of the Scherer 3 baghouse, SCR, and scrubber projects and associated equipment. The O&M project includes the cost of anhydrous ammonia, hydrated lime, limestone and general expenses.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
Capital - During the first half of 2020, Plant Crist completed design of the Underground Injection Control (UIC) pipeline expansion and is scheduled to begin construction in the September 2020 timeframe. The expansion will allow Plant Crist to utilize two additional wells for disposal of wastewater generated from the gypsum storage area.
For cyber security requirements, Plant Crist replaced the Unit 6 SCR and scrubber controls and Plant Scherer replaced the Unit 3 air emission control equipment. Plant Daniel completed the Unit 2 low NOx burner replacement and installed a new underground injection well liner.

O&M - Existing air quality controls have ensured compliance with existing state and federal regulations.

Project Costs:
(January 1, 2020 to December 31, 2020)
Capital - Project revenue requirements are estimated to be $122,344,829.
O&M - Estimated costs are projected to be $16,998,777.

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FORM: 42-5P

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - During 2021, Gulf plans to complete construction of the Crist UIC pipeline expansion and pump replacement. Plant Crist has also projected costs to upgrade the wastewater treatment plant controls and to begin closing or repurposing the gypsum storage area. Engineering and design for the gypsum storage area project will be completed during the first half of 2021 and construction is scheduled to begin during third quarter. Plant Daniel will be replacing the scrubber mist eliminator in 2021 and Plant Scherer will be retrofitting the Unit 3 activated carbon feed system. Estimated project Revenue requirements for the projection period are $120,631,648.

O&M - Estimated project costs for the projection period are $23,673,016.

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FORM: 42-5P

Project Title: General Water Quality
Project No. 27 (Capital)

Project Description: The General Water Quality project includes capital expenditures required to ensure compliance with Gulf Power's NPDES IWW permits. Gulf purchased a boat in 2007 for surface water sampling required by the Plants Crist, Smith and Scholz NPDES permits. The permits had new conditions, which required Gulf to establish a biological evaluation plan and implementation schedule for each plant. Plant Crist installed additional groundwater monitoring wells during 2017-2019 for compliance with the plant's NPDES IWW permit.

The Plant Crist industrial wastewater permit and FDEP Order 17-1224 require Gulf to complete FDEP approved rehabilitation actions by July 23, 2023 for the Plant Crist closed ash landfill (CAL). Gulf plans to regrade the surface of the CAL and then cap it with a low permeability synthetic material to reduce water infiltration, to provide separation of ash and stormwater, and to provide stability improvements as recommended in the FDEP action plan that was approved on August 28, 2019.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
Gulf has completed the 90% design plans for the Crist CAL project and will be bidding out the project as soon as the design is finalized. Construction is scheduled to begin in late 2020.

Project Costs:
(January 1, 2020 to December 31, 2020)
Project revenue requirements are estimated to be $441,535.

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Project Projections:

(January 1, 2021 to December 31, 2021)

Gulf plans to regrade the surface of the Plant Crist Closed Ash Landfill (CAL) and cap it with a low permeability synthetic material during 2021. FDEP Order 17-1224 requires Gulf to complete FDEP approved rehabilitation actions by July 23, 2023. Estimated project revenue requirements for the projection period are $1,328,597.

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FORM: 42-5P

Project Title: Coal Combustion Residuals
Project No. 28 (Capital) and 23 (O&M)

Project Description: The Coal Combustion Residuals (CCR) program is related to the regulation of CCRs by the U.S. EPA and state environmental Agencies. For Gulf's generating plants, these regulatory compliance obligations are required pursuant to either the CCR rule adopted in April of 2015 or through NPDES IWW permit requirements issued by FDEP. The rule applies to CCR Units at Gulf's Plants Crist, Scherer, Smith, and Daniel. Plant Scherer is also regulated under Georgia's Environmental Protection Division CCR Rule.

In addition, pursuant to its authority granted under the Clean Water Act, the FDEP issues IWW permits for each of Gulf's generating facilities. A NPDES permit renewal for Plant Scholz (FL0002283) was issued in 2015 which requires closure of the existing on-site ash pond. Costs required to complete the Scholz pond closure are included under this project.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
Capital - During 2020, construction activities for the Scholz and Smith pond closure projects, Daniel dry bottom ash handling and wastewater treatment systems, and Scherer CCR ash and wastewater management projects continued. The 2020 Scholz ash pond closure activities include transferring CCR material to a dry stack area within the footprint of the pond and construction of a new stormwater management system. The Plant Smith activities include ash excavation and construction of a new lined industrial wastewater treatment pond and associated infrastructure. Gulf plans to complete construction of the lined wastewater pond and associated pump station in 2020.

The Daniel Unit 2 bottom ash handling project was recently completed and the Unit 1 project is scheduled to be placed in-service in Fourth Quarter 2020. Plant Daniel is also installing a temporary wastewater treatment system for low volume wastewater streams

while the plant closes and repurposes the bottom ash pond to serve as a low volume wastewater treatment pond.

Construction of the Scherer CCR wastewater management system has continued in 2020, which includes installing wastewater treatment systems for wastewater streams that have been routed to the ash pond such as coal pile runoff, equipment wash water, and precipitator sumps. Construction of Cell 3 of the onsite landfill for CCR storage has been delayed to November 2020 to better align with current storage capacity needs. Plant Scherer also plans to continue preliminary design of a new CCR landfill later in 2020.

O&M costs include compliance monitoring and reporting as required by the CCR rule.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $9,160,660, which is $1,658,908 or 22.1% higher than previously projected. The variance is primarily due to the addition of costs for CCR activities at Plant Daniel which were deferred from the 2020 Projection Filing pending further review and approval from the Mississippi Public Service Commission ("MPSC"). In addition, approximately $5.9 million of costs associated with ash excavation and placement for the Smith and Scholz ash pond closure projects were reclassified from O&M to capital to properly account for the deferred regulatory asset. These ash handling costs are appropriate for inclusion in the total ash pond closure costs to be amortized over the life of the project.

As noted in Gulf's 2019 and 2020 ECRC Projection Filings filed August 24, 2018 and August 30, 2019, respectively, Plant Daniel is required to construct new wastewater treatment and ash handling systems for the wastewater streams being routed to the pond (bottom ash and low volume wastewater) prior to beginning ash pond closure activities. Plant Daniel is installing a temporary wastewater treatment system for low volume wastewater streams while the plant closes and repurposes the bottom ash pond to serve as

a low volume wastewater treatment pond. The Unit 1 and Unit 2 dry bottom ash conversion projects are scheduled to be placed in-service in 2020 to meet the Federal requirements provided by the Coal Combustion Residual rule located in Title 40 Code of Federal Regulations ("CFR") Parts 257 and 261 or "CCR Rule" adopted in April of 2015 and amended in July of 2018.

Plant Daniel must cease placing CCR and non-CCR wastewater streams into the ash pond, in accordance with the CCR Rule unless Mississippi Power Company ("MPC") commits to permanent cessation of coal operations at Plant Daniel under the alternative closure requirements in 40 CFR Part 257.103. MPC has determined that early retirement of the Daniel Units 1 and 2 is not a viable compliance option due to transmission constraints and the reliability risk in the region. In addition, early retirement would require acceleration of other closure obligations.

On October 28, 2019 the MPSC issued an order finding that public convenience and necessity require the proposed Plant Daniel CCR projects. As documented in the MPSC Order, Plant Daniel must complete the following CCR projects in sequential order to comply with the Federal CCR requirements; 1) conversion of the bottom ash collection systems to new systems that will not require use of the ash pond for the discharge of any CCR waste stream, 2) closure of the ash pond by removing all CCR material, and 3) construction of a new low-volume wastewater treatment system on the site of the former ash pond. The ash pond closure must be completed within five years of the commencement of closure activities pursuant to 40 CFR Part 257.102 unless the facility demonstrates that it was not feasible to complete closure within the required timeframes due to factors beyond the facility's control.

The Gulf Power CCR Program was approved for recovery through the ECRC in PSC Order No. 15-0536-FOF-EI, with the reasonableness and prudence of individual project expenditures subject to the Commission's review in future proceedings. The Daniel CCR

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wastewater treatment and bottom ash handling costs originally projected for the 2019 timeframe were included in Gulf's ECRC jurisdictional revenue requirements approved in PSC Order No. 2018-0594-FOF-EI. As noted in Gulf Witness Markey's 2019 ECRC Projection testimony, Plant Daniel will need "to construct a new wastewater treatment and ash handling system" prior to beginning closure activities. Gulf included capital expenditures for the Daniel CCR projects in its 2019 Projection Filing; however, the projects were subsequently delayed until 2020 due to timing of vendor selection and equipment fabrication.

As explained in Gulf Witness Markey's 2020 ECRC Projection Testimony, Plant Daniel dry bottom ash handling projects are scheduled to be placed in-service in 2020 in order to meet the Federal CCR requirement to cease receipt of CCR and non-CCR wastestreams (40 CFR Part 257.101). Gulf has projected $19.1 million of ECRC capital expenditures for the Daniel CCR projects and $3.3 million for cost of removal for the Daniel ash pond closure in the 2020 Actual/Estimated filing. The Daniel CCR project meets the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI in that the costs associated with it are not recovered through any other cost recovery mechanism or through base rates and will be incurred after April 13, 1993. In addition, the Daniel CCR projects are necessary to ensure compliance with the Federal CCR Rule, which is legally mandated under a governmentally imposed environmental regulation.

O&M - Project expenditures are estimated to be $1,000,844, which is $5,865,228 or 85.4% lower than previously projected. The variance is primarily due to reclassification of ash handling costs required for the Smith and Scholz ash pond closure projects as discussed above.

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Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - During 2021, construction activities for the Scholz ash pond closure project will include completing construction of a new stormwater management system and capping the dry stack area with closure turf material. Plant Smith plans to continue construction of the second lined industrial wastewater treatment pond and will proceed with construction of the new unlined pond. During pond construction, CCR material will be excavated and transported to a new dry stack area within the footprint of the pond.

Construction of the Scherer CCR wastewater management system will continue in 2021 and construction will begin on Cell 3 of the onsite landfill for CCR storage. Scherer will proceed with the ash pond closure project as well as siting studies and preliminary design for a new landfill.

Construction of the Plant Daniel pond closure project and operation of the temporary wastewater treatment systems will continue in 2021.

Estimated CCR project revenue requirements for the projection period are $15,320,788.

O&M - Estimated project costs for the projection period are $1,745,127.

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FORM: 42-5P

Project Title: Steam Electric Power Effluent Limitations Guidelines and Standards
Project No. 29 (Capital)

Project Description: In 2015, the EPA finalized revisions to the steam electric effluent limitations guidelines (ELG) rule, which imposes stringent technology-based requirements for certain waste streams from steam electric generating units. The revised technology-based limits and compliance dates will require extensive modifications to existing ash and flue gas desulfurization (FGD) scrubber wastewater management systems or the installation and operation of new wastewater management systems. Compliance applicability dates in the 2015 rule ranged from November 1, 2018 to December 31, 2023.

On September 18, 2017, EPA published a final rule in the Federal Register that delayed the earliest ELG applicability date for FGD wastewater and bottom ash transport water from the original (2015 rule) "as soon as possible date" of November 1, 2018 to a new "as soon as possible" date of November 1, 2020, to allow time for EPA to reconsider the requirements for FGD wastewater and bottom ash transport water. The 2017 rule did not change the latest applicability date or "no later than" date of December 31, 2023; however, in November 2019, EPA issued a proposed rule that provides for up to a two year extension for the applicability dates for scrubber wastewater if approved by the State environmental agencies.

State environmental agencies will incorporate specific applicability dates in the NPDES permitting process based on requirements provided for each waste stream. The EPA plans to finalize the rulemaking in late 2020.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
The Scherer ELG project has been delayed pending EPA's final rulemaking.

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FORM: 42-5P

Project Costs:

(January 1, 2020 to December 31, 2020)

The majority of the costs projected in 2020 for engineering and design of the Scherer scrubber wastewater treatment system have been delayed to 2021. Project revenue requirements are estimated to be $669,659.

Project Projections:

(January 1, 2021 to December 31, 2021)

Gulf has projected expenditures in 2021 for Gulf's ownership portion of costs needed to complete engineering and design of the Scherer scrubber wastewater treatment system and to begin initial material procurement. Estimated project revenue requirements for the projection period are $734,321.

GULF POWER COMPANY
PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: 316(b) Intake Structure Regulation
Project No. 30 (Capital)

Project Description: On August 15, 2014, the EPA published final regulations under Section 316(b) of the Clean Water Act for cooling water intake structures at existing electric generating facilities. The rule found in Title 40 Parts 122 and 125 of the Code of Federal Regulations became effective on October 14, 2014, requiring existing facilities withdrawing greater than 2 million gallons per day (MGD) to adopt one of seven options for addressing impingement at the entrance to existing cooling water intake structures. Although the ultimate 316(b) compliance strategy and design will be approved by the state environmental permitting agencies, with possible input from the U.S. Fish and Wildlife Service, National Marine Fisheries Service (Services), and EPA, Gulf Power's preliminary studies indicate Plant Smith will need to install new lower capacity intake pumps. The Plant Smith industrial wastewater permit required Gulf to submit information required under the Cooling Water Intake Structure 316(b) rule with its 2019 permit renewal for FDEP review and approval.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
New lower capacity intake pumps and associated equipment have been ordered.

Project Costs:
(January 1, 2020 to December 31, 2020)
Project revenue requirements are estimated to be $114,654, which is $97,137 or 45.9% lower than previously projected. The variance is primarily due to delays associated with replacing the Plant Smith intake pumps with new lower capacity pumps. Gulf initially planned to place the new pumps in-service in March 2020; however, the replacement was re-scheduled to January 2021 in order to coordinate with other projects.

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Project Projections:

(January 1, 2021 to December 31, 2021)

Gulf plans to complete installation of new lower capacity intake pumps at Plant Smith in January 2021. Estimated project revenue requirements for the projection period are $493,620.

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PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: NO_x Allowances

Project No. Capital (32 and 33) and O&M (26 and 27)

Project Description: Although the retrofit installations set forth in Gulf's Air Quality Compliance Program significantly reduce emissions, the projects will not result in Gulf achieving CAIR compliance levels without the purchase of some emission allowances. Thus, Gulf's Compliance Program called for the purchase of allowances as needed. The purchase of allowances in conjunction with the retrofit projects comprised the most reasonable, cost-effective means for Gulf to meet CAIR requirements. CAIR has now been replaced by CSAPR. Annual NOx allowances are currently required for Scherer Unit 3. Seasonal NOx allowances are currently required for Scherer Unit 3 and Daniel Units 1 and 2.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Allowances have been surrendered as required.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $1,240.

O&M - Project costs are estimated to be $2,908.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $6,179.

O&M - Estimated project costs for the projection period are $2,201.

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PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: SO_2 Allowances

Project No. Capital (34) and O&M (28)

Project Description: Part of Gulf's strategy to comply with the Acid Rain Program under the Clean Air Act Amendments of 1990 was to bring several of Gulf's Phase II generating units into compliance early and bank the SO_2 allowances associated with those units. SO_2 reductions under the CAIR program utilized this program requiring an increased rate of surrender beginning in 2010. Gulf's bank has slowly been drawn down over the years due to more allowances being consumed than are allocated to Gulf by EPA. Gulf proposed to meet this shortfall by executing forward contracts to secure allowances supplemented with forward contracts, swaps, and spot market purchases of allowances as prices dictate. Gulf executed forward contacts to secure allowances during 2006, 2007, and 2009. With the Plant Crist and Daniel scrubbers in service the need to purchase additional allowances has ceased and the bank is growing.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Allowances have been surrendered as required.

Project Costs:

(January 1, 2020 to December 31, 2020)

Capital - Project revenue requirements are estimated to be $437,357.

O&M - Project costs are estimated to be $30,417.

Project Projections:

(January 1, 2021 to December 31, 2021)

Capital - Estimated project revenue requirements for the projection period are $431,577.

O&M - Estimated project costs for the projection period are $1,687.

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PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Air Emission Fees

Project No. 2 (O&M)

Project Description: Air Emission Fees are the annual fees required by the Florida Department of Environmental Protection (FDEP), Georgia Environmental Protection Division (EPD), and Mississippi Department of Environmental Quality (MDEQ) under Title V of the 1990 CAAA.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Fees have been paid by associated due dates.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project costs are estimated to be $270,737.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project costs for the projection period are $279,230.

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PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Title V

Project No. 3 (O&M)

Project Description: Title V expenses are associated with preparation of the CAAA Title V permit applications and the subsequent implementation of Title V permits. Renewal of the Title V permits is on a five-year cycle (i.e. 2019, 2024, etc.). Title V permits are periodically revised between renewals to incorporate major changes or modifications of a source.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Gulf has maintained compliance with its Title V permits and submitted permit renewals and modifications as required.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project costs are estimated to be $217,024.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project costs for the projection period are $195,866.

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PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Asbestos Fees

Project No. 4 (O&M)

Project Description: Asbestos Fees include both annual and individual project fees due to the FDEP for asbestos abatement projects.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Fees are paid as required by FDEP.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project costs are estimated to be $1,000.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project costs for the projection period are $1,500.

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FORM: 42-5P

Project Title: General Water Quality
Project No. 6 (O&M)

Project Description: The General Water Quality program includes activities undertaken pursuant to the Company's NPDES IWW permits including dechlorination, toxicity sampling, surface and groundwater monitoring studies as well as associated assessment activities. This project also includes expenses for Gulf's 316(b) Cooling Water Intake program, Storm Water Maintenance, and the Impoundment Integrity project.

Project Accomplishments:
(January 1, 2020 to December 31, 2020)
Activities are on-going in compliance with applicable environmental laws, rules, and regulations.

Project Costs:
(January 1, 2020 to December 31, 2020)
Project expenditures are estimated to be $1,257,915, which is $284,645 or 18.5% lower than previously projected. The variance is primarily due to costs for Plant Smith's industrial wastewater permit renewal being less than originally projected and costs for Plant Daniel's groundwater monitoring being lower than previously projected. In addition, Plant Crist was not able to complete the Spring 2020 thermal study due to Units 4 and 5 being offline during the sampling period. The variance was partially offset by costs projected for modification of the Plant Scholz stormwater pond and additional Plant Scholz wastewater sampling expenses.

Project Projections:
(January 1, 2021 to December 31, 2021)
Estimated project costs for the projection period are $1,632,757.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: State NPDES Administration

Project No. 8 (O&M)

Project Description: The State NPDES Administration fees are required by the State of Florida's NPDES program administration. Annual and five-year permit renewal fees are required for the NPDES industrial wastewater permits at Plants Crist, Smith and Scholz.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Gulf has complied with the NPDES program administration fee submittal schedule.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project costs are estimated to be $49,516.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project costs for the projection period are $35,000.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Environmental Auditing/Assessment

Project No. 10 (O&M)

Project Description: The Environmental Auditing/Assessment program ensures continued compliance with environmental laws, rules, and regulations through auditing and/or assessment of company facilities and operations.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Assessments completed to date have demonstrated compliance with environmental laws, rules, and regulations.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project costs are estimated to be $2,588.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project costs for the projection period are $32,931.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: General Solid and Hazardous Waste

Project No. 11 (O&M)

Project Description: The General Solid and Hazardous Waste program involves the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes as required by federal and state regulations. This project also includes O&M expenses associated with Gulf's Spill Prevention Control and Countermeasures (SPCC) plans. The program includes expenses for Gulf's generating and power delivery facilities.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Gulf has complied with all hazardous and solid waste regulations.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project costs are estimated to be $957,980.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project costs for the projection period are $822,664.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Project Title: Above Ground Storage Tanks

Project No. 12 (O&M)

Project Description: The aboveground storage tank projects are required under the provisions of state storage tank regulation, Chapter 62-762, F.A.C. which includes specific performance standards applicable to storage tank systems. These performance standards include maintenance requirements, installation of secondary containment and cathodic protection systems, as well as periodic tank integrity testing.

Project Accomplishments:

(January 1, 2020 to December 31, 2020)

Gulf has complied with all applicable storage tank requirements.

Project Costs:

(January 1, 2020 to December 31, 2020)

Project costs are estimated to be $196,679.

Project Projections:

(January 1, 2021 to December 31, 2021)

Estimated project costs for the projection period are $243,131.

GULF POWER COMPANY

PROJECT PROGRESS REPORTS

FORM: 42-5P

Note: The following projects are omitted from Forms 1P through 8P. These projects do not have actual or estimated costs and have been removed from filing for administrative efficiency.

Project No.	Project Title	Type of Expense
1	Sulfur	O&M
9	Lead & Copper Rule	O&M
13	Low NOx	O&M
14	Ash Pond Diversion Curtains	O&M
15	Mercury Emissions	O&M
16	Sodium Injection	O&M
17	Gulf Coast Ozone Study	O&M
18	SPCC Substation	O&M
21	Maximum Achievable Control Technology Information Collection Request	O&M
25 and 31	Mercury Allowances	O&M and Capital

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ENERGY DEMAND ALLOCATION % BY RATE CLASS

FORM: 42-6P

JANUARY 2021 THROUGH DECEMBER 2021

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
RATE CLASS	Average 12 CP Load Factor at Meter (%)	Average NCP Load Factor at Meter (%)	Projected Sales at Meter (kWh)	Projected Avg 12 CP at Meter (kW)	Projected Avg NCP at Meter (kW)	Demand Loss Expansion Factor	Energy Loss Expansion Factor	Projected Sales at Generation (kWh)	Projected Avg 12 CP at Generation (kW)	Projected Avg NCP at Generation (kW)	Percentage of kWh Sales at Generation (%)	Percentage of 12 CP Demand at Generation (%)	Percentage of NCP Demand at Generation (%)
RS, RSVP, RSTOU	58.270328%	56.128051%	5,396,609,000	1,057,230	1,097,582	1.00609343	1.00559591	5,426,807,938	1,063,672	1,104,270	50.56646%	58.08655%	55.34698%
GS	57.224449%	51.437382%	311,376,000	62,115	69,104	1.00608241	1.00559477	313,118,077	62,493	69,524	2.91760%	3.41272%	3.48461%
GSD, GSDT, GSTOU	74.102156%	65.785406%	2,481,479,000	382,275	430,603	1.00590017	1.00544671	2,494,994,896	384,530	433,144	23.24812%	20.99899%	21.70954%
LP, LPT	85.094449%	76.438817%	751,037,000	100,753	112,161	0.98747379	0.99210885	745,110,454	99,490	110,756	6.94287%	5.43312%	5.55121%
PX, PXT, RTP, SBS	84.969637%	72.991745%	1,644,662,000	220,958	257,216	0.96884429	0.97666479	1,606,283,467	214,073	249,203	14.96719%	11.69043%	12.49026%
OS-I/II	767.743332%	49.337282%	98,024,000	1,458	22,681	1.00619545	1.00560119	98,573,051	1,467	22,821	0.91849%	0.08009%	1.14381%
OS-III	98.645916%	98.645916%	46,881,000	5,425	5,425	1.00617773	1.00558881	47,143,009	5,459	5,459	0.43927%	0.29810%	0.27359%
TOTAL			10,730,068,000	1,830,213	1,994,772			10,732,030,892	1,831,185	1,995,176	100.00000%	100.00000%	100.00000%

Notes:

(A) Average 12 CP load factor based on actual 2018 load research data
(B) Average NCP load factor based on actual load research data
(C) Projected kWh sales for the period January 2021 - December 2021
(D) Calculated: (Col A) / (8,760 x Col C), (8,760 hours = the # of hours in 1 year)
(H) Column C x Column G
(I) Column D x Column F
(J) Column E x Column F
(K) Column H/ total for Column H
(L) Column I / total for Column I
(M) Column J / total for Column J

8,760

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF ENVIRONMENTAL COST RECOVERY FACTORS

FORM: 42-7P

JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE CLASS	Percentage of kWh Sales at Generation (%) [a]	Percentage of 12 CP Demand at Generation (%) [b]	Percentage of NCP Demand at Generation (%) [c]	Energy Related Cost ($) [d]	12 CP Demand Related Cost ($) [e]	NCP Demand Related Cost ($) [f]	Total Environmental Costs ($) [g]	Projected Sales at Meter (kWh) [h]	ECRC Factor (cents/kWh) [i]
RS, RSVP, RSTOU	50.56646%	58.08655%	55.34698%	$15,070,487	$90,529,228	$1,874,262	$107,473,977	5,396,609,000	1.992
GS	2.91760%	3.41272%	3.48461%	$869,542	$5,318,803	$118,002	$6,306,347	311,376,000	2.025
GSD, GSDT, GSTOU	23.24812%	20.99899%	21.70954%	$6,928,713	$32,727,410	$735,169	$40,391,292	2,481,479,000	1.628
LP, LPT	6.94287%	5.43312%	5.55121%	$2,069,206	$8,467,643	$187,985	$10,724,834	751,037,000	1.428
PX, PXT, RTP, SBS	14.96719%	11.69043%	12.49026%	$4,460,720	$18,219,805	$422,968	$23,103,494	1,644,662,000	1.405
OS-I/II	0.91849%	0.08009%	1.14381%	$273,741	$124,822	$38,734	$437,296	98,024,000	0.446
OS-III	0.43927%	0.29810%	0.27359%	$130,917	$464,596	$9,265	$604,778	46,881,000	1.290
TOTAL				$29,803,326	$155,852,307	$3,386,385	$189,042,018	10,730,068,000	1.762

(a) From Form 42-6P, Col K
(b) From Form 42-6P, Col L
(c) From Form 42-6P, Col M
(d) Total Energy $ from Form 42-1P, Line 5
(e) Total 12 CP Demand $ from Form 42-1P, Line 5
(f) Total NCP Demand $ from Form 42-1P, Line 5
(g) Col 5 + Col 6 + Col 7
(h) Projected kWh sales for the period January 2021 through December 2021
(i) Col 9 / Col 10

GULF POWER COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

FORM: 42-8P

GULF POWER COMPANY

FORECASTED 2021
CAPITAL STRUCTURE AND COST RATES [a]

Equity @ 10.25%

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG TERM DEBT	923,869,652	28.122%	2.91%	0.8195%	0.82%
SHORT_TERM_DEBT	327,115,529	9.957%	0.51%	0.0508%	0.05%
PREFERRED_STOCK	0	0.000%	0.00%	0.0000%	0.00%
CUSTOMER_DEPOSITS	20,576,210	0.626%	2.66%	0.0167%	0.02%
COMMON_EQUITY [b]	1,439,015,272	43.802%	10.25%	4.4897%	5.95%
DEFERRED_INCOME_TAX	558,510,509	17.000%	0.00%	0.0000%	0.00%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0.00%	0.0000%	0.00%
WEIGHTED COST	16,176,661	0.492%	7.38%	0.0363%	0.05%
TOTAL	$3,285,263,833	100.00%		5.4130%	6.88%

CALCULATION OF THE WEIGHTED COST FOR INVESTMENT TAX CREDITS

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$923,869,652	39.10%	2.914%	1.139%	1.139%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	1,439,015,272	60.90%	10.250%	6.242%	8.270%
TOTAL	$2,362,884,924	100.00%		7.382%	9.410%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	0.8195%
SHORT TERM DEBT	0.0508%
CUSTOMER DEPOSITS	0.0167%
TAX CREDITS -WEIGHTED	0.0056%
TOTAL DEBT	**0.8925%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.4897%
TAX CREDITS -WEIGHTED	0.0307%
TOTAL EQUITY	**4.5205%**
TOTAL	5.4130%
PRE-TAX EQUITY	5.9891%
PRE-TAX TOTAL	6.8816%

Note:
(a) Forecasted capital structure includes a deferred income tax proration adjustment consistent with FPSC Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(b) Cost rate for common equity represents Gulf's mid-point return on equity approved by the FPSC in Order No. PSC-17-0178-S-EI, Docket Nos. 160186-EI and 160170-EI.

GULF - 2021 PROJECTED SEPARATION FACTORS

CLAUSES

	SUMMARY
DEMAND	
Total Production/Transmission	0.972343
Non-Stratified Production	1.000000
Intermediate Strata Production	0.975922
Peaking Strata Production	0.760860
Distribution	0.981419
ENERGY	
Total Sales	0.974597
Non-Stratified Sales	1.000000
Intermediate Strata Sales	0.975922
Peaking Strata Sales	0.760860
GENERAL PLANT	
General Plant	0.969888

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 18
PARTY: RLH-4
DESCRIPTION: Calculation of Stratified Separation Factors

GULF POWER COMPANY

CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS
TOTAL PRODUCTION & TRANSMISSION (NO ADJUSTMENTS)

RATE CLASS	(1) **2021 PROJ** Average 12CPKW @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** Average 12CPKW @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	1,077,395	1.00609343	1,083,960	
GS	64,217	1.00608241	64,607	
GSD/GSDT	390,857	1.00590017	393,163	
LP/LPT	111,599	0.98747379	110,201	
PX/PXT/RTP/CSA/SBS	240,698	0.96884429	233,199	
OSI/OSII	1,547	1.00619545	1,556	
OSIII	5,350	1.00617773	5,383	
JURISDICTIONAL	1,891,662		1,892,070	**97.23427%**
FPU (INT)	32,668	0.94895250	31,000	1.59310%
FPU (PEAK)	24,045	0.94895250	22,818	1.17262%
NON-JURISDICTIONAL	56,713		53,818	**2.76573%**
TERRITORIAL	1,948,375		1,945,887	100.00000%

GULF POWER COMPANY

CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS

NON-STRATIFIED PRODUCTION

RATE CLASS	(1) **2021 PROJ** Average 12CPKW @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** Average 12CPKW @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	1,077,395	1.00609343	1,083,960	
GS	64,217	1.00608241	64,607	
GSD/GSDT	390,857	1.00590017	393,163	
LP/LPT	111,599	0.98747379	110,201	
PX/PXT/RTP/CSA/SBS	240,698	0.96884429	233,199	
OSI/OSII	1,547	1.00619545	1,556	
OSIII	5,350	1.00617773	5,383	
JURISDICTIONAL	1,891,662		1,892,070	**100.00000%**
FPU (INT)	0	0.94895250	0	0.00000%
FPU (PEAK)	0	0.94895250	0	0.00000%
NON-JURISDICTIONAL	0		0	**0.00000%**
TERRITORIAL	1,891,662		1,892,070	100.00000%

GULF POWER COMPANY

CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS

INTERMEDIATE STRATA PRODUCTION

RATE CLASS	(1) **2021 PROJ** Average 12CPKW @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** Average 12CPKW @ GENER.	(3) ADJUSTED Average 12CPKW @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	1,077,395	1.00609343	1,083,960	1,083,960	
GS	64,217	1.00608241	64,607	64,607	
GSD/GSDT	390,857	1.00590017	393,163	393,163	
LP/LPT	111,599	0.98747379	110,201	110,201	
PX/PXT/RTP/CSA/SBS	240,698	0.96884429	233,199	233,199	
OSI/OSII	1,547	1.00619545	1,556	1,556	
OSIII	5,350	1.00617773	5,383	5,383	
JURISDICTIONAL	1,891,662		1,892,070	1,892,070	**97.59223%**
FPU (INT)	32,668	0.94895250	31,000	46,681	2.40777%
FPU (PEAK)	0	0.94895250	0	0	0.00000%
NON-JURISDICTIONAL	32,668		31,000	46,681	**2.40777%**
TERRITORIAL	1,924,330		1,923,070	1,938,750	100.00000%

GULF POWER COMPANY
CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS
PEAKING STRATA PRODUCTION

RATE CLASS	(1) **2021 PROJ** Average 12CPKW @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** Average 12CPKW @ GENER.	(3) ADJUSTED Average 12CPKW @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	1,077,395	1.00609343	1,083,960	1,083,960	
GS	64,217	1.00608241	64,607	64,607	
GSD/GSDT	390,857	1.00590017	393,163	393,163	
LP/LPT	111,599	0.98747379	110,201	110,201	
PX/PXT/RTP/CSA/SBS	240,698	0.96884429	233,199	233,199	
OSI/OSII	1,547	1.00619545	1,556	1,556	
OSIII	5,350	1.00617773	5,383	5,383	
JURISDICTIONAL	1,891,662		1,892,070	1,892,070	**76.08600%**
FPU (INT)	0	0.94895250	0	0	0.00000%
FPU (PEAK)	24,045	0.94895250	22,818	594,682	23.91400%
NON-JURISDICTIONAL	24,045		22,818	594,682	**23.91400%**
TERRITORIAL	1,915,708		1,914,887	2,486,751	100.00000%

GULF POWER COMPANY

CALCULATION OF 2021 PROJ KWH SALES AT GENERATION BY RATE CLASS
TOTAL SALES (NO ADJUSTMENTS)

RATE CLASS	(1) **2021 PROJ** TOTAL KWH SALES @ METER	(2) ENERGY LOSS EXPANSION FACTOR	(3) **2021 PROJ** TOTAL KWH SALES @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	5,528,121,218	1.00559591	5,559,056,087	
GS	328,640,315	1.00559477	330,478,982	
GSD/GSDT	2,501,334,147	1.00544671	2,514,958,189	
LP/LPT	826,617,738	0.99210885	820,094,773	
PX/PXT/RTP/CSA/SBS	1,787,605,854	0.97666479	1,745,891,696	
OSI/OSII	100,786,002	1.00560119	101,350,524	
OSIII	46,997,061	1.00558881	47,259,719	
JURISDICTIONAL	11,120,102,335		11,119,089,969	**97.45969%**
FPU (INT)	207,769,383	0.96249530	199,977,054	1.75281%
FPU (PEAK)	93,345,665	0.96249530	89,844,763	0.78750%
NON-JURISDICTIONAL	301,115,048		289,821,817	**2.54031%**
TERRITORIAL	11,421,217,383		11,408,911,786	100.00000%

GULF POWER COMPANY

CALCULATION OF 2021 PROJ KWH SALES AT GENERATION BY RATE CLASS

NON-STRATIFIED SALES

RATE CLASS	(1) **2021 PROJ** TOTAL KWH SALES @ METER	(2) ENERGY LOSS EXPANSION FACTOR	(3) **2021 PROJ** TOTAL KWH SALES @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	5,528,121,218	1.00559591	5,559,056,087	
GS	328,640,315	1.00559477	330,478,982	
GSD/GSDT	2,501,334,147	1.00544671	2,514,958,189	
LP/LPT	826,617,738	0.99210885	820,094,773	
PX/PXT/RTP/CSA/SBS	1,787,605,854	0.97666479	1,745,891,696	
OSI/OSII	100,786,002	1.00560119	101,350,524	
OSIII	46,997,061	1.00558881	47,259,719	
JURISDICTIONAL	11,120,102,335		11,119,089,969	**100.00000%**
FPU (INT)	0	0.96249530	0	0.00000%
FPU (PEAK)	0	0.96249530	0	0.00000%
NON-JURISDICTIONAL	0		0	**0.00000%**
TERRITORIAL	11,120,102,335		11,119,089,969	100.00000%

GULF POWER COMPANY

CALCULATION OF 2021 PROJ KWH SALES AT GENERATION BY RATE CLASS

INTERMEDIATE STRATA SALES

RATE CLASS	(1) **2021 PROJ** TOTAL KWH SALES @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** TOTAL KWH SALES @ GENER.	(3) ADJUSTED TOTAL KWH SALES @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	5,528,121,218	1.00559591	5,559,056,087	5,559,056,087	
GS	328,640,315	1.00559477	330,478,982	330,478,982	
GSD/GSDT	2,501,334,147	1.00544671	2,514,958,189	2,514,958,189	
LP/LPT	826,617,738	0.99210885	820,094,773	820,094,773	
PX/PXT/RTP/CSA/SBS	1,787,605,854	0.97666479	1,745,891,696	1,745,891,696	
OSI/OSII	100,786,002	1.00560119	101,350,524	101,350,524	
OSIII	46,997,061	1.00558881	47,259,719	47,259,719	
JURISDICTIONAL	11,120,102,335		11,119,089,969	11,119,089,969	**97.59223%**
FPU (INT)	207,769,383	0.96249530	199,977,054	274,326,931	2.40777%
FPU (PEAK)	0	0.96249530	0	0	0.00000%
NON-JURISDICTIONAL	207,769,383		199,977,054	274,326,931	**2.40777%**
TERRITORIAL	11,327,871,718		11,319,067,023	11,393,416,900	100.00000%

0.97592233

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Calculation of Separation Factor
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GULF POWER COMPANY
CALCULATION OF 2021 PROJ 12CPKW AT GENERATION BY RATE CLASS
PEAKING STRATA PRODUCTION

RATE CLASS	(1) **2021 PROJ** TOTAL KWH SALES @ METER	(2) DEMAND LOSS EXPANSION FACTOR	(3) **2021 PROJ** TOTAL KWH SALES @ GENER.	(3) ADJUSTED TOTAL KWH SALES @ GENER.	(4) **2021 PROJ** JURIS. ALLOCATOR
RS/RSVP	5,528,121,218	1.00559591	5,559,056,087	5,559,056,087	
GS	328,640,315	1.00559477	330,478,982	330,478,982	
GSD/GSDT	2,501,334,147	1.00544671	2,514,958,189	2,514,958,189	
LP/LPT	826,617,738	0.99210885	820,094,773	820,094,773	
PX/PXT/RTP/CSA/SBS	1,787,605,854	0.97666479	1,745,891,696	1,745,891,696	
OSI/OSII	100,786,002	1.00560119	101,350,524	101,350,524	
OSIII	46,997,061	1.00558881	47,259,719	47,259,719	
JURISDICTIONAL	11,120,102,335		11,119,089,969	11,119,089,969	**76.08600%**
FPU (INT)	0	0.96249530	0	0	0.00000%
FPU (PEAK)	93,345,665	0.96249530	89,844,763	3,494,754,515	0.80155%
NON-JURISDICTIONAL	93,345,665		89,844,763	3,494,754,515	**23.91400%**
TERRITORIAL	11,213,448,000		11,208,934,732	14,613,844,484	100.00000%

GULF POWER COMPANY

CALCULATION OF 2021 PROJ DISTRIBUTION AND GENERAL PLANT SEPARTION FACTORS

DISTRIBUTION AND GENERAL PLANT

($000s)

Description	Total Total Adjusted Utility	Unit Power Sales	Total Adjusted Utility Net Of UPS	Jurisdictional Amount	Jurisdictional Separation Factor
DISTRIBUTION					
Land and Land Rights	3,137	0	3,137	3,063	0.9764106
Structures and Improvements	25,825	0	25,825	25,226	0.9768054
Station Equipment	214,784	0	214,784	210,928	0.9820471
DISTRIBUTION			243,746	239,217	0.9814192
GENERAL PLANT	205,892	1,339	204,553	201,302	0.9841068

Gulf Power Company
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available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA has decided to use the following technical standards in this rule: (1) RCRA Subpart D, Section 257.70 liner design criteria for new CCR landfills and any lateral expansion of a CCR landfill includes voluntary consensus standards developed by ASTM International and EPA test methods such as SW–846, (2) Section 257.71 liner design criteria for existing CCR surface impoundments include voluntary consensus standards developed by ASTM International and EPA test methods such as SW–846, (3) Section 257.72 liner design criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment include voluntary consensus standards developed by ASTM International and EPA test methods such as SW–846, and (4) Section 257.73 structural stability standards for new and existing surface impoundments use the ASTM D 698 and 1557 standards for embankment compaction.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (E.O.) 12898 (59 FR 7629, Feb. 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

EPA's risk assessment for this action did not separately evaluate either minority or low income populations. However, to evaluate the demographic characteristics of communities that may be affected by the CCR rule, the RIA compares the demographic characteristics of populations surrounding coal-fired electric utility plants with broader population data for two geographic areas: (1) One-mile radius from CCR management units (*i.e.,* landfills and impoundments) likely to be affected by groundwater releases from both landfills and impoundments; and (2) watershed catchment areas downstream of surface impoundments that receive surface water run-off and releases from CCR impoundments and are at risk of being contaminated from CCR impoundment discharges (*e.g.,* unintentional overflows, structural failures, and intentional periodic discharges).

For the population as a whole 24.8% belong to a minority group and 11.3% falls below the Federal Poverty Level. For the population living within one mile of plants with surface impoundments 16.1% belong to a minority group and 13.2% live below the Federal Poverty Level. These minority and low-income populations are not disproportionately high compared to the general population. The percentage of minority residents of the entire population living within the catchment areas downstream of surface impoundments is disproportionately high relative to the general population, *i.e.,* 28.7%, versus 24.8% for the national population. Also, the percentage of the population within the catchment areas of surface impoundments that is below the Federal Poverty Level is disproportionately high compared with the general population, *i.e.,* 18.6% versus 11.3% nationally.

Comparing the population percentages of minority and low income residents within one mile of landfills to those percentages in the general population, EPA found that minority and low-income residents make up a smaller percentage of the populations near landfills than they do in the general population, *i.e.,* minorities comprised 16.6% of the population near landfills versus 24.8% nationwide and low-income residents comprised 8.6% of the population near landfills versus 11.3% nationwide. In summary, although populations within the catchment areas of plants with surface impoundments appear to have disproportionately high percentages of minority and low-income residents relative to the nationwide average, populations surrounding plants with landfills do not. Because landfills are less likely than impoundments to experience surface water run-off and releases, catchment areas were not considered for landfills.

Because the CCR rule is risk-reducing, with reductions in risk occurring largely within the surface water catchment zones around, and groundwater beneath, coal-fired electric utility plants, the rule will not result in new disproportionate risks to minority or low-income populations.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective 180 days after its publication in the **Federal Register**.

List of Subjects

40 CFR Part 257

Environmental protection, Beneficial use, Coal combustion products, Coal combustion residuals, Coal combustion waste, Disposal, Hazardous waste, Landfill, Surface impoundment.

40 CFR Part 261

Environmental protection, Hazardous waste, Recycling, Reporting and recordkeeping requirements.

Dated: December 19, 2014.

Gina McCarthy,

Administrator.

For the reasons set out in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 257—CRITERIA FOR CLASSIFICATION OF SOLID WASTE DISPOSAL FACILITIES AND PRACTICES

■ 1. The authority citation for part 257 continues to read as follows:

Authority: 42 U.S.C. 6907(a)(3), 6912(a)(1), 6944(a); 33 U.S.C. 1345(d) and (e).

■ 2. Section 257.1 is amended by:

■ a. Adding a sentence at the end of paragraph (a) introductory text;

■ b. Revising paragraphs (a)(1) and (2); and

■ c. Adding paragraph (c)(12).

The revisions and additions read as follows:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 19
PARTY: MWS-1 (19)
DESCRIPTION: Federal Coal Combustion Residuals

§ 257.1 Scope and purpose.

(a) * * * Unless otherwise provided, the criteria in §§ 257.50 through 257.107 are adopted for determining which CCR landfills and CCR surface impoundments pose a reasonable probability of adverse effects on health or the environment under sections 1008(a)(3) and 4004(a) of the Act.

(1) Facilities failing to satisfy any of the criteria in §§ 257.1 through 257.4 or §§ 257.5 through 257.30 or §§ 257.50 through 257.107 are considered open dumps, which are prohibited under section 4005 of the Act.

(2) Practices failing to satisfy any of the criteria in §§ 257.1 through 257.4 or §§ 257.5 through 257.30 or §§ 257.50 through 257.107 constitute open dumping, which is prohibited under section 4005 of the Act.

* * * * *

(c) * * *

(12) Except as otherwise specifically provided in subpart D of this part, the criteria in subpart A of this part do not apply to CCR landfills, CCR surface impoundments, and lateral expansions of CCR units, as those terms are defined in subpart D of this part. Such units are instead subject to subpart D of this part.

■ 3. Section 257.2 is amended by adding in alphabetical order definitions for ''CCR landfill'' and ''CCR surface impoundment'' to read as follows:

§ 257.2 Definitions.

* * * * *

CCR landfill means an area of land or an excavation that receives CCR and which is not a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface coal mine, or a cave. For purposes of this subpart, a CCR landfill also includes sand and gravel pits and quarries that receive CCR, CCR piles, and any practice that does not meet the definition of a beneficial use of CCR.

CCR surface impoundment means a natural topographic depression, man-made excavation, or diked area, which is designed to hold an accumulation of CCR and liquids, and the unit treats, stores, or disposes of CCR.

* * * * *

■ 4. Part 257 is amended by:

■ a. Adding and reserving subpart C; and

■ b. Adding subpart D.

The additions read as follows:

Subpart C—[Reserved]

Subpart D—Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments

General Provisions

Sec.
257.50 Scope and purpose.
257.51 Effective date of this subpart.
257.52 Applicability of other regulations.
257.53 Definitions.

Location Restrictions

257.60 Placement above the uppermost aquifer.
257.61 Wetlands.
257.62 Fault areas.
257.63 Seismic impact zones.
257.64 Unstable areas.

Design Criteria

257.70 Design criteria for new CCR landfills and any lateral expansion of a CCR landfill.
257.71 Liner design criteria for existing CCR surface impoundments.
257.72 Design criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment.
257.73 Structural integrity criteria for existing CCR surface impoundments.
257.74 Structural integrity criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment.

Operating Criteria

257.80 Air criteria.
257.81 Run-on and run-off controls for CCR landfills.
257.82 Hydrologic and hydraulic capacity requirements for CCR surface impoundments.
257.83 Inspection requirements for CCR surface impoundments.
257.84 Inspection requirements for CCR landfills.

Groundwater Monitoring and Corrective Action

257.90 Applicability.
257.91 Groundwater monitoring systems.
257.92 [Reserved]
257.93 Groundwater sampling and analysis requirements.
257.94 Detection monitoring program.
257.95 Assessment monitoring program.
257.96 Assessment of corrective measures.
257.97 Selection of remedy.
257.98 Implementation of the corrective action program.

Closure and Post-Closure Care

257.100 Inactive CCR surface impoundments.
257.101 Closure or retrofit of CCR units.
257.102 Criteria for conducting the closure or retrofit of CCR units.
257.103 Alternative closure requirements.
257.104 Post-closure care requirements.

Recordkeeping, Notification, and Posting of Information to the Internet

257.105 Recordkeeping requirements.
257.106 Notification requirements.
257.107 Publicly accessible internet site requirements.

Subpart D—Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments

§ 257.50 Scope and purpose.

(a) This subpart establishes minimum national criteria for purposes of determining which solid waste disposal facilities and solid waste management practices do not pose a reasonable probability of adverse effects on health or the environment under sections 1008(a)(3) and 4004(a) of the Resource Conservation and Recovery Act.

(b) This subpart applies to owners and operators of new and existing landfills and surface impoundments, including any lateral expansions of such units that dispose or otherwise engage in solid waste management of CCR generated from the combustion of coal at electric utilities and independent power producers. Unless otherwise provided in this subpart, these requirements also apply to disposal units located off-site of the electric utility or independent power producer. This subpart also applies to any practice that does not meet the definition of a beneficial use of CCR.

(c) This subpart also applies to inactive CCR surface impoundments at active electric utilities or independent power producers, regardless of the fuel currently used at the facility to produce electricity.

(d) This subpart does not apply to CCR landfills that have ceased receiving CCR prior to October 19, 2015.

(e) This subpart does not apply to electric utilities or independent power producers that have ceased producing electricity prior to October 19, 2015.

(f) This subpart does not apply to wastes, including fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated at facilities that are not part of an electric utility or independent power producer, such as manufacturing facilities, universities, and hospitals. This subpart also does not apply to fly ash, bottom ash, boiler slag, and flue gas desulfurization materials, generated primarily from the combustion of fuels (including other fossil fuels) other than coal, for the purpose of generating electricity unless the fuel burned consists of more than fifty percent (50%) coal on a total heat input or mass input basis, whichever results in the greater mass feed rate of coal.

(g) This subpart does not apply to practices that meet the definition of a beneficial use of CCR.

(h) This subpart does not apply to CCR placement at active or abandoned underground or surface coal mines.

(i) This subpart does not apply to municipal solid waste landfills that receive CCR.

§ 257.51 Effective date of this subpart.

The requirements of this subpart take effect on October 19, 2015.

§ 257.52 Applicability of other regulations.

(a) Compliance with the requirements of this subpart does not affect the need for the owner or operator of a CCR landfill, CCR surface impoundment, or lateral expansion of a CCR unit to comply with all other applicable federal, state, tribal, or local laws or other requirements.

(b) Any CCR landfill, CCR surface impoundment, or lateral expansion of a CCR unit continues to be subject to the requirements in §§ 257.3–1, 257.3–2, and 257.3–3.

§ 257.53 Definitions.

The following definitions apply to this subpart. Terms not defined in this section have the meaning given by RCRA.

Acre foot means the volume of one acre of surface area to a depth of one foot.

Active facility or *active electric utilities or independent power producers* means any facility subject to the requirements of this subpart that is in operation on October 14, 2015. An electric utility or independent power producer is in operation if it is generating electricity that is provided to electric power transmission systems or to electric power distribution systems on or after October 14, 2015. An off-site disposal facility is in operation if it is accepting or managing CCR on or after October 14, 2015.

Active life or *in operation* means the period of operation beginning with the initial placement of CCR in the CCR unit and ending at completion of closure activities in accordance with § 257.102.

Active portion means that part of the CCR unit that has received or is receiving CCR or non-CCR waste and that has not completed closure in accordance with § 257.102.

Aquifer means a geologic formation, group of formations, or portion of a formation capable of yielding usable quantities of groundwater to wells or springs.

Area-capacity curves means graphic curves which readily show the reservoir water surface area, in acres, at different elevations from the bottom of the reservoir to the maximum water surface, and the capacity or volume, in acre-feet, of the water contained in the reservoir at various elevations.

Areas susceptible to mass movement means those areas of influence (*i.e.,* areas characterized as having an active or substantial possibility of mass movement) where, because of natural or human-induced events, the movement of earthen material at, beneath, or adjacent to the CCR unit results in the downslope transport of soil and rock material by means of gravitational influence. Areas of mass movement include, but are not limited to, landslides, avalanches, debris slides and flows, soil fluctuation, block sliding, and rock fall.

Beneficial use of CCR means the CCR meet all of the following conditions:

(1) The CCR must provide a functional benefit;

(2) The CCR must substitute for the use of a virgin material, conserving natural resources that would otherwise need to be obtained through practices, such as extraction;

(3) The use of the CCR must meet relevant product specifications, regulatory standards or design standards when available, and when such standards are not available, the CCR is not used in excess quantities; and

(4) When unencapsulated use of CCR involving placement on the land of 12,400 tons or more in non-roadway applications, the user must demonstrate and keep records, and provide such documentation upon request, that environmental releases to groundwater, surface water, soil and air are comparable to or lower than those from analogous products made without CCR, or that environmental releases to groundwater, surface water, soil and air will be at or below relevant regulatory and health-based benchmarks for human and ecological receptors during use.

Closed means placement of CCR in a CCR unit has ceased, and the owner or operator has completed closure of the CCR unit in accordance with § 257.102 and has initiated post-closure care in accordance with § 257.104.

Coal combustion residuals (CCR) means fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity by electric utilities and independent power producers.

CCR fugitive dust means solid airborne particulate matter that contains or is derived from CCR, emitted from any source other than a stack or chimney.

CCR landfill or landfill means an area of land or an excavation that receives CCR and which is not a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface coal mine, or a cave. For purposes of this subpart, a CCR landfill also includes sand and gravel pits and quarries that receive CCR, CCR piles, and any practice that does not meet the definition of a beneficial use of CCR.

CCR pile or pile means any non-containerized accumulation of solid, non-flowing CCR that is placed on the land. CCR that is beneficially used off-site is not a CCR pile.

CCR surface impoundment or impoundment means a natural topographic depression, man-made excavation, or diked area, which is designed to hold an accumulation of CCR and liquids, and the unit treats, stores, or disposes of CCR.

CCR unit means any CCR landfill, CCR surface impoundment, or lateral expansion of a CCR unit, or a combination of more than one of these units, based on the context of the paragraph(s) in which it is used. This term includes both new and existing units, unless otherwise specified.

Dike means an embankment, berm, or ridge of either natural or man-made materials used to prevent the movement of liquids, sludges, solids, or other materials.

Displacement means the relative movement of any two sides of a fault measured in any direction.

Disposal means the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste as defined in section 1004(27) of the Resource Conservation and Recovery Act into or on any land or water so that such solid waste, or constituent thereof, may enter the environment or be emitted into the air or discharged into any waters, including groundwaters. For purposes of this subpart, disposal does not include the storage or the beneficial use of CCR.

Downstream toe means the junction of the downstream slope or face of the CCR surface impoundment with the ground surface.

Encapsulated beneficial use means a beneficial use of CCR that binds the CCR into a solid matrix that minimizes its mobilization into the surrounding environment.

Existing CCR landfill means a CCR landfill that receives CCR both before and after October 14, 2015, or for which construction commenced prior to October 14, 2015 and receives CCR on or after October 14, 2015. A CCR landfill has commenced construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical

construction and a continuous on-site, physical construction program had begun prior to October 14, 2015.

Existing CCR surface impoundment means a CCR surface impoundment that receives CCR both before and after October 14, 2015, or for which construction commenced prior to October 14, 2015 and receives CCR on or after October 14, 2015. A CCR surface impoundment has commenced construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical construction and a continuous on-site, physical construction program had begun prior to October 14, 2015.

Facility means all contiguous land, and structures, other appurtenances, and improvements on the land, used for treating, storing, disposing, or otherwise conducting solid waste management of CCR. A facility may consist of several treatment, storage, or disposal operational units (*e.g.,* one or more landfills, surface impoundments, or combinations of them).

Factor of safety (Safety factor) means the ratio of the forces tending to resist the failure of a structure to the forces tending to cause such failure as determined by accepted engineering practice.

Fault means a fracture or a zone of fractures in any material along which strata on one side have been displaced with respect to that on the other side.

Flood hydrograph means a graph showing, for a given point on a stream, the discharge, height, or other characteristic of a flood as a function of time.

Freeboard means the vertical distance between the lowest point on the crest of the impoundment dike and the surface of the waste contained therein.

Free liquids means liquids that readily separate from the solid portion of a waste under ambient temperature and pressure.

Groundwater means water below the land surface in a zone of saturation.

Hazard potential classification means the possible adverse incremental consequences that result from the release of water or stored contents due to failure of the diked CCR surface impoundment or mis-operation of the diked CCR surface impoundment or its appurtenances. The hazardous potential classifications include high hazard potential CCR surface impoundment, significant hazard potential CCR surface impoundment, and low hazard potential CCR surface impoundment, which terms mean:

(1) *High hazard potential CCR surface impoundment* means a diked surface impoundment where failure or mis-operation will probably cause loss of human life.

(2) *Low hazard potential CCR surface impoundment* means a diked surface impoundment where failure or mis-operation results in no probable loss of human life and low economic and/or environmental losses. Losses are principally limited to the surface impoundment owner's property.

(3) *Significant hazard potential CCR surface impoundment* means a diked surface impoundment where failure or mis-operation results in no probable loss of human life, but can cause economic loss, environmental damage, disruption of lifeline facilities, or impact other concerns.

Height means the vertical measurement from the downstream toe of the CCR surface impoundment at its lowest point to the lowest elevation of the crest of the CCR surface impoundment.

Holocene means the most recent epoch of the Quaternary period, extending from the end of the Pleistocene Epoch, at 11,700 years before present, to present.

Hydraulic conductivity means the rate at which water can move through a permeable medium (*i.e.,* the coefficient of permeability).

Inactive CCR surface impoundment means a CCR surface impoundment that no longer receives CCR on or after October 14, 2015 and still contains both CCR and liquids on or after October 14, 2015.

Incised CCR surface impoundment means a CCR surface impoundment which is constructed by excavating entirely below the natural ground surface, holds an accumulation of CCR entirely below the adjacent natural ground surface, and does not consist of any constructed diked portion.

Indian country or *Indian lands* means:

(1) All land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and including rights-of-way running throughout the reservation;

(2) All dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of the State; and

(3) All Indian allotments, the Indian titles to which have not been extinguished, including rights of way running through the same.

Indian Tribe or *Tribe* means any Indian tribe, band, nation, or community recognized by the Secretary of the Interior and exercising substantial governmental duties and powers on Indian lands.

Inflow design flood means the flood hydrograph that is used in the design or modification of the CCR surface impoundments and its appurtenant works.

In operation means the same as *active life.*

Karst terrain means an area where karst topography, with its characteristic erosional surface and subterranean features, is developed as the result of dissolution of limestone, dolomite, or other soluble rock. Characteristic physiographic features present in karst terranes include, but are not limited to, dolines, collapse shafts (sinkholes), sinking streams, caves, seeps, large springs, and blind valleys.

Lateral expansion means a horizontal expansion of the waste boundaries of an existing CCR landfill or existing CCR surface impoundment made after October 14, 2015.

Liquefaction factor of safety means the factor of safety (safety factor) determined using analysis under liquefaction conditions.

Lithified earth material means all rock, including all naturally occurring and naturally formed aggregates or masses of minerals or small particles of older rock that formed by crystallization of magma or by induration of loose sediments. This term does not include man-made materials, such as fill, concrete, and asphalt, or unconsolidated earth materials, soil, or regolith lying at or near the earth surface.

Maximum horizontal acceleration in lithified earth material means the maximum expected horizontal acceleration at the ground surface as depicted on a seismic hazard map, with a 98% or greater probability that the acceleration will not be exceeded in 50 years, or the maximum expected horizontal acceleration based on a site-specific seismic risk assessment.

New CCR landfill means a CCR landfill or lateral expansion of a CCR landfill that first receives CCR or commences construction after October 14, 2015. A new CCR landfill has commenced construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical construction and a continuous on-site, physical construction program had begun after October 14, 2015. Overfills are also considered new CCR landfills.

New CCR surface impoundment means a CCR surface impoundment or lateral expansion of an existing or new CCR surface impoundment that first receives CCR or commences construction after October 14, 2015. A

new CCR surface impoundment has commenced construction if the owner or operator has obtained the federal, state, and local approvals or permits necessary to begin physical construction and a continuous on-site, physical construction program had begun after October 14, 2015.

Operator means the person(s) responsible for the overall operation of a CCR unit.

Overfill means a new CCR landfill constructed over a closed CCR surface impoundment.

Owner means the person(s) who owns a CCR unit or part of a CCR unit.

Poor foundation conditions mean those areas where features exist which indicate that a natural or human-induced event may result in inadequate foundation support for the structural components of an existing or new CCR unit. For example, failure to maintain static and seismic factors of safety as required in §§ 257.73(e) and 257.74(e) would cause a poor foundation condition.

Probable maximum flood means the flood that may be expected from the most severe combination of critical meteorologic and hydrologic conditions that are reasonably possible in the drainage basin.

Qualified person means a person or persons trained to recognize specific appearances of structural weakness and other conditions which are disrupting or have the potential to disrupt the operation or safety of the CCR unit by visual observation and, if applicable, to monitor instrumentation.

Qualified professional engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in the state where the CCR unit(s) is located.

Recognized and generally accepted good engineering practices means engineering maintenance or operation activities based on established codes, widely accepted standards, published technical reports, or a practice widely recommended throughout the industry. Such practices generally detail approved ways to perform specific engineering, inspection, or mechanical integrity activities.

Retrofit means to remove all CCR and contaminated soils and sediments from the CCR surface impoundment, and to ensure the unit complies with the requirements in § 257.72

Representative sample means a sample of a universe or whole (*e.g.,* waste pile, lagoon, and groundwater) which can be expected to exhibit the average properties of the universe or whole. See EPA publication SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Chapter 9 (available at *http://www.epa.gov/epawaste/hazard/testmethods/sw846/online/index.htm*) for a discussion and examples of representative samples.

Run-off means any rainwater, leachate, or other liquid that drains over land from any part of a CCR landfill or lateral expansion of a CCR landfill.

Run-on means any rainwater, leachate, or other liquid that drains over land onto any part of a CCR landfill or lateral expansion of a CCR landfill.

Sand and gravel pit or quarry means an excavation for the extraction of aggregate, minerals or metals. The term sand and gravel pit and/or quarry does not include subsurface or surface coal mines.

Seismic factor of safety means the factor of safety (safety factor) determined using analysis under earthquake conditions using the peak ground acceleration for a seismic event with a 2% probability of exceedance in 50 years, equivalent to a return period of approximately 2,500 years, based on the U.S. Geological Survey (USGS) seismic hazard maps for seismic events with this return period for the region where the CCR surface impoundment is located.

Seismic impact zone means an area having a 2% or greater probability that the maximum expected horizontal acceleration, expressed as a percentage of the earth's gravitational pull (g), will exceed 0.10 g in 50 years.

Slope protection means engineered or non-engineered measures installed on the upstream or downstream slope of the CCR surface impoundment to protect the slope against wave action or erosion, including but not limited to rock riprap, wooden pile, or concrete revetments, vegetated wave berms, concrete facing, gabions, geotextiles, or fascines.

Solid waste management or management means the systematic administration of the activities which provide for the collection, source separation, storage, transportation, processing, treatment, or disposal of solid waste.

State means any of the fifty States in addition to the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands.

State Director means the chief administrative officer of the lead state agency responsible for implementing the state program regulating disposal in CCR landfills, CCR surface impoundments, and all lateral expansions of a CCR unit.

Static factor of safety means the factor of safety (safety factor) determined using analysis under the long-term, maximum storage pool loading condition, the maximum surcharge pool loading condition, and under the end-of-construction loading condition.

Structural components mean liners, leachate collection and removal systems, final covers, run-on and run-off systems, inflow design flood control systems, and any other component used in the construction and operation of the CCR unit that is necessary to ensure the integrity of the unit and that the contents of the unit are not released into the environment.

Unstable area means a location that is susceptible to natural or human-induced events or forces capable of impairing the integrity, including structural components of some or all of the CCR unit that are responsible for preventing releases from such unit. Unstable areas can include poor foundation conditions, areas susceptible to mass movements, and karst terrains.

Uppermost aquifer means the geologic formation nearest the natural ground surface that is an aquifer, as well as lower aquifers that are hydraulically interconnected with this aquifer within the facility's property boundary. Upper limit is measured at a point nearest to the natural ground surface to which the aquifer rises during the wet season.

Waste boundary means a vertical surface located at the hydraulically downgradient limit of the CCR unit. The vertical surface extends down into the uppermost aquifer.

Location Restrictions

§ 257.60 Placement above the uppermost aquifer.

(a) New CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must be constructed with a base that is located no less than 1.52 meters (five feet) above the upper limit of the uppermost aquifer, or must demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including the seasonal high water table). The owner or operator must demonstrate by the dates specified in paragraph (c) of this section

that the CCR unit meets the minimum requirements for placement above the uppermost aquifer.

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(c) The owner or operator of the CCR unit must complete the demonstration required by paragraph (a) of this section by the date specified in either paragraph (c)(1) or (2) of this section.

(1) For an existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (c)(1) of this section is subject to the requirements of § 257.101(b)(1).

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstration showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the internet requirements specified in § 257.107(e).

§ 257.61 Wetlands.

(a) New CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must not be located in wetlands, as defined in § 232.2 of this chapter, unless the owner or operator demonstrates by the dates specified in paragraph (c) of this section that the CCR unit meets the requirements of paragraphs (a)(1) through (5) of this section.

(1) Where applicable under section 404 of the Clean Water Act or applicable state wetlands laws, a clear and objective rebuttal of the presumption that an alternative to the CCR unit is reasonably available that does not involve wetlands.

(2) The construction and operation of the CCR unit will not cause or contribute to any of the following:

(i) A violation of any applicable state or federal water quality standard;

(ii) A violation of any applicable toxic effluent standard or prohibition under section 307 of the Clean Water Act;

(iii) Jeopardize the continued existence of endangered or threatened species or result in the destruction or adverse modification of a critical habitat, protected under the Endangered Species Act of 1973; and

(iv) A violation of any requirement under the Marine Protection, Research, and Sanctuaries Act of 1972 for the protection of a marine sanctuary.

(3) The CCR unit will not cause or contribute to significant degradation of wetlands by addressing all of the following factors:

(i) Erosion, stability, and migration potential of native wetland soils, muds and deposits used to support the CCR unit;

(ii) Erosion, stability, and migration potential of dredged and fill materials used to support the CCR unit;

(iii) The volume and chemical nature of the CCR;

(iv) Impacts on fish, wildlife, and other aquatic resources and their habitat from release of CCR;

(v) The potential effects of catastrophic release of CCR to the wetland and the resulting impacts on the environment; and

(vi) Any additional factors, as necessary, to demonstrate that ecological resources in the wetland are sufficiently protected.

(4) To the extent required under section 404 of the Clean Water Act or applicable state wetlands laws, steps have been taken to attempt to achieve no net loss of wetlands (as defined by acreage and function) by first avoiding impacts to wetlands to the maximum extent reasonable as required by paragraphs (a)(1) through (3) of this section, then minimizing unavoidable impacts to the maximum extent reasonable, and finally offsetting remaining unavoidable wetland impacts through all appropriate and reasonable compensatory mitigation actions (*e.g.,* restoration of existing degraded wetlands or creation of man-made wetlands); and

(5) Sufficient information is available to make a reasoned determination with respect to the demonstrations in paragraphs (a)(1) through (4) of this section.

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(c) The owner or operator of the CCR unit must complete the demonstrations required by paragraph (a) of this section by the date specified in either paragraph (c)(1) or (2) of this section.

(1) For an existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (c)(1) of this section is subject to the requirements of § 257.101(b)(1).

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstrations showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(d) The owner or operator must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the Internet requirements specified in § 257.107(e).

§ 257.62 Fault areas.

(a) New CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must not be located within 60 meters (200 feet) of the outermost damage zone of a fault that has had displacement in Holocene time unless the owner or operator demonstrates by the dates specified in paragraph (c) of this section that an alternative setback distance of less than 60 meters (200 feet) will prevent damage to the structural integrity of the CCR unit.

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(c) The owner or operator of the CCR unit must complete the demonstration

required by paragraph (a) of this section by the date specified in either paragraph (c)(1) or (2) of this section.

(1) For an existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (c)(1) of this section is subject to the requirements of § 257.101(b)(1).

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstration showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the Internet requirements specified in § 257.107(e).

§ 257.63 Seismic impact zones.

(a) New CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must not be located in seismic impact zones unless the owner or operator demonstrates by the dates specified in paragraph (c) of this section that all structural components including liners, leachate collection and removal systems, and surface water control systems, are designed to resist the maximum horizontal acceleration in lithified earth material for the site.

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(c) The owner or operator of the CCR unit must complete the demonstration required by paragraph (a) of this section by the date specified in either paragraph (c)(1) or (2) of this section.

(1) For an existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (c)(1) of this section is subject to the requirements of § 257.101(b)(1).

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstration showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the Internet requirements specified in § 257.107(e).

§ 257.64 Unstable areas.

(a) An existing or new CCR landfill, existing or new CCR surface impoundment, or any lateral expansion of a CCR unit must not be located in an unstable area unless the owner or operator demonstrates by the dates specified in paragraph (d) of this section that recognized and generally accepted good engineering practices have been incorporated into the design of the CCR unit to ensure that the integrity of the structural components of the CCR unit will not be disrupted.

(b) The owner or operator must consider all of the following factors, at a minimum, when determining whether an area is unstable:

(1) On-site or local soil conditions that may result in significant differential settling;

(2) On-site or local geologic or geomorphologic features; and

(3) On-site or local human-made features or events (both surface and subsurface).

(c) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the demonstration meets the requirements of paragraph (a) of this section.

(d) The owner or operator of the CCR unit must complete the demonstration required by paragraph (a) of this section by the date specified in either paragraph (d)(1) or (2) of this section.

(1) For an existing CCR landfill or existing CCR surface impoundment, the owner or operator must complete the demonstration no later than October 17, 2018.

(2) For a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit, the owner or operator must complete the demonstration no later than the date of initial receipt of CCR in the CCR unit.

(3) The owner or operator has completed the demonstration required by paragraph (a) of this section when the demonstration is placed in the facility's operating record as required by § 257.105(e).

(4) An owner or operator of an existing CCR surface impoundment or existing CCR landfill who fails to demonstrate compliance with the requirements of paragraph (a) of this section by the date specified in paragraph (d)(1) of this section is subject to the requirements of § 257.101(b)(1) or (d)(1), respectively.

(5) An owner or operator of a new CCR landfill, new CCR surface impoundment, or any lateral expansion of a CCR unit who fails to make the demonstration showing compliance with the requirements of paragraph (a) of this section is prohibited from placing CCR in the CCR unit.

(e) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(e), the notification requirements specified in § 257.106(e), and the Internet requirements specified in § 257.107(e).

Design Criteria

§ 257.70 Design criteria for new CCR landfills and any lateral expansion of a CCR landfill.

(a)(1) New CCR landfills and any lateral expansion of a CCR landfill must be designed, constructed, operated, and maintained with either a composite liner that meets the requirements of paragraph (b) of this section or an alternative composite liner that meets the requirements in paragraph (c) of this section, and a leachate collection and removal system that meets the requirements of paragraph (d) of this section.

(2) Prior to construction of an overfill the underlying surface impoundment must meet the requirements of § 257.102(d).

(b) A *composite liner* must consist of two components; the upper component

consisting of, at a minimum, a 30-mil geomembrane liner (GM), and the lower component consisting of at least a two-foot layer of compacted soil with a hydraulic conductivity of no more than 1×10^{-7} centimeters per second (cm/sec). GM components consisting of high density polyethylene (HDPE) must be at least 60-mil thick. The GM or upper liner component must be installed in direct and uniform contact with the compacted soil or lower liner component. The composite liner must be:

(1) Constructed of materials that have appropriate chemical properties and sufficient strength and thickness to prevent failure due to pressure gradients (including static head and external hydrogeologic forces), physical contact with the CCR or leachate to which they are exposed, climatic conditions, the stress of installation, and the stress of daily operation;

(2) Constructed of materials that provide appropriate shear resistance of the upper and lower component interface to prevent sliding of the upper component including on slopes;

(3) Placed upon a foundation or base capable of providing support to the liner and resistance to pressure gradients above and below the liner to prevent failure of the liner due to settlement, compression, or uplift; and

(4) Installed to cover all surrounding earth likely to be in contact with the CCR or leachate.

(c) If the owner or operator elects to install an alternative composite liner, all of the following requirements must be met:

(1) An *alternative composite liner* must consist of two components; the upper component consisting of, at a minimum, a 30-mil GM, and a lower component, that is not a geomembrane, with a liquid flow rate no greater than the liquid flow rate of two feet of compacted soil with a hydraulic conductivity of no more than 1×10^{-7} cm/sec. GM components consisting of high density polyethylene (HDPE) must be at least 60-mil thick. If the lower component of the alternative liner is compacted soil, the GM must be installed in direct and uniform contact with the compacted soil.

(2) The owner or operator must obtain certification from a qualified professional engineer that the liquid flow rate through the lower component of the alternative composite liner is no greater than the liquid flow rate through two feet of compacted soil with a hydraulic conductivity of 1×10^{-7} cm/sec. The hydraulic conductivity for the two feet of compacted soil used in the comparison shall be no greater than 1×10^{-7} cm/sec. The hydraulic conductivity of any alternative to the two feet of compacted soil must be determined using recognized and generally accepted methods. The liquid flow rate comparison must be made using Equation 1 of this section, which is derived from Darcy's Law for gravity flow through porous media.

$$\text{(Eq. 1)} \qquad \frac{Q}{A} = q = k\left(\frac{h}{t} + 1\right)$$

Where,

Q = flow rate (cubic centimeters/second);
A = surface area of the liner (squared centimeters);
q = flow rate per unit area (cubic centimeters/second/squared centimeter);
k = hydraulic conductivity of the liner (centimeters/second);
h = hydraulic head above the liner (centimeters); and
t = thickness of the liner (centimeters).

(3) The alternative composite liner must meet the requirements specified in paragraphs (b)(1) through (4) of this section.

(d) The *leachate collection and removal system* must be designed, constructed, operated, and maintained to collect and remove leachate from the landfill during the active life and post-closure care period. The leachate collection and removal system must be:

(1) Designed and operated to maintain less than a 30-centimeter depth of leachate over the composite liner or alternative composite liner;

(2) Constructed of materials that are chemically resistant to the CCR and any non-CCR waste managed in the CCR unit and the leachate expected to be generated, and of sufficient strength and thickness to prevent collapse under the pressures exerted by overlying waste, waste cover materials, and equipment used at the CCR unit; and

(3) Designed and operated to minimize clogging during the active life and post-closure care period.

(e) Prior to construction of the CCR landfill or any lateral expansion of a CCR landfill, the owner or operator must obtain a certification from a qualified professional engineer that the design of the composite liner (or, if applicable, alternative composite liner) and the leachate collection and removal system meets the requirements of this section.

(f) Upon completion of construction of the CCR landfill or any lateral expansion of a CCR landfill, the owner or operator must obtain a certification from a qualified professional engineer that the composite liner (or, if applicable, alternative composite liner) and the leachate collection and removal system has been constructed in accordance with the requirements of this section.

(g) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the Internet requirements specified in § 257.107(f).

§ 257.71 Liner design criteria for existing CCR surface impoundments.

(a)(1) No later than October 17, 2016, the owner or operator of an existing CCR surface impoundment must document whether or not such unit was constructed with any one of the following:

(i) A liner consisting of a minimum of two feet of compacted soil with a hydraulic conductivity of no more than 1×10^{-7} cm/sec;

(ii) A composite liner that meets the requirements of § 257.70(b); or

(iii) An alternative composite liner that meets the requirements of § 257.70(c).

(2) The hydraulic conductivity of the compacted soil must be determined using recognized and generally accepted methods.

(3) An existing CCR surface impoundment is considered to be an existing unlined CCR surface impoundment if either:

(i) The owner or operator of the CCR unit determines that the CCR unit is not constructed with a liner that meets the requirements of paragraphs (a)(1)(i), (ii), or (iii) of this section; or

(ii) The owner or operator of the CCR unit fails to document whether the CCR unit was constructed with a liner that meets the requirements of paragraphs (a)(1)(i), (ii), or (iii) of this section.

(4) All existing unlined CCR surface impoundments are subject to the requirements of § 257.101(a).

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer attesting that the documentation as to whether a CCR unit meets the requirements of paragraph (a) of this section is accurate.

(c) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the Internet requirements specified in § 257.107(f).

§ 257.72 Liner design criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment.

(a) New CCR surface impoundments and lateral expansions of existing and new CCR surface impoundments must

be designed, constructed, operated, and maintained with either a composite liner or an alternative composite liner that meets the requirements of § 257.70(b) or (c).

(b) Any liner specified in this section must be installed to cover all surrounding earth likely to be in contact with CCR. Dikes shall not be constructed on top of the composite liner.

(c) Prior to construction of the CCR surface impoundment or any lateral expansion of a CCR surface impoundment, the owner or operator must obtain certification from a qualified professional engineer that the design of the composite liner or, if applicable, the design of an alternative composite liner complies with the requirements of this section.

(d) Upon completion, the owner or operator must obtain certification from a qualified professional engineer that the composite liner or if applicable, the alternative composite liner has been constructed in accordance with the requirements of this section.

(e) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the Internet requirements specified in § 257.107(f).

§ 257.73 Structural integrity criteria for existing CCR surface impoundments.

(a) The requirements of paragraphs (a)(1) through (4) of this section apply to all existing CCR surface impoundments, except for those existing CCR surface impoundments that are incised CCR units. If an incised CCR surface impoundment is subsequently modified (*e.g.,* a dike is constructed) such that the CCR unit no longer meets the definition of an incised CCR unit, the CCR unit is subject to the requirements of paragraphs (a)(1) through (4) of this section.

(1) No later than, December 17, 2015, the owner or operator of the CCR unit must place on or immediately adjacent to the CCR unit a permanent identification marker, at least six feet high showing the identification number of the CCR unit, if one has been assigned by the state, the name associated with the CCR unit and the name of the owner or operator of the CCR unit.

(2) *Periodic hazard potential classification assessments.* (i) The owner or operator of the CCR unit must conduct initial and periodic hazard potential classification assessments of the CCR unit according to the timeframes specified in paragraph (f) of this section. The owner or operator must document the hazard potential classification of each CCR unit as either a high hazard potential CCR surface impoundment, a significant hazard potential CCR surface impoundment, or a low hazard potential CCR surface impoundment. The owner or operator must also document the basis for each hazard potential classification.

(ii) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial hazard potential classification and each subsequent periodic classification specified in paragraph (a)(2)(i) of this section was conducted in accordance with the requirements of this section.

(3) *Emergency Action Plan (EAP)*—(i) *Development of the plan.* No later than April 17, 2017, the owner or operator of a CCR unit determined to be either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment under paragraph (a)(2) of this section must prepare and maintain a written EAP. At a minimum, the EAP must:

(A) Define the events or circumstances involving the CCR unit that represent a safety emergency, along with a description of the procedures that will be followed to detect a safety emergency in a timely manner;

(B) Define responsible persons, their respective responsibilities, and notification procedures in the event of a safety emergency involving the CCR unit;

(C) Provide contact information of emergency responders;

(D) Include a map which delineates the downstream area which would be affected in the event of a CCR unit failure and a physical description of the CCR unit; and

(E) Include provisions for an annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders.

(ii) *Amendment of the plan.* (A) The owner or operator of a CCR unit subject to the requirements of paragraph (a)(3)(i) of this section may amend the written EAP at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(f)(6). The owner or operator must amend the written EAP whenever there is a change in conditions that would substantially affect the EAP in effect.

(B) The written EAP must be evaluated, at a minimum, every five years to ensure the information required in paragraph (a)(3)(i) of this section is accurate. As necessary, the EAP must be updated and a revised EAP placed in the facility's operating record as required by § 257.105(f)(6).

(iii) *Changes in hazard potential classification.* (A) If the owner or operator of a CCR unit determines during a periodic hazard potential assessment that the CCR unit is no longer classified as either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment, then the owner or operator of the CCR unit is no longer subject to the requirement to prepare and maintain a written EAP beginning on the date the periodic hazard potential assessment documentation is placed in the facility's operating record as required by § 257.105(f)(5).

(B) If the owner or operator of a CCR unit classified as a low hazard potential CCR surface impoundment subsequently determines that the CCR unit is properly re-classified as either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment, then the owner or operator of the CCR unit must prepare a written EAP for the CCR unit as required by paragraph (a)(3)(i) of this section within six months of completing such periodic hazard potential assessment.

(iv) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the written EAP, and any subsequent amendment of the EAP, meets the requirements of paragraph (a)(3) of this section.

(v) *Activation of the EAP.* The EAP must be implemented once events or circumstances involving the CCR unit that represent a safety emergency are detected, including conditions identified during periodic structural stability assessments, annual inspections, and inspections by a qualified person.

(4) The CCR unit and surrounding areas must be designed, constructed, operated, and maintained with vegetated slopes of dikes not to exceed a height of 6 inches above the slope of the dike, except for slopes which are protected with an alternate form(s) of slope protection.

(b) The requirements of paragraphs (c) through (e) of this section apply to an owner or operator of an existing CCR surface impoundment that either:

(1) Has a height of five feet or more and a storage volume of 20 acre-feet or more; or

(2) Has a height of 20 feet or more.

(c)(1) No later than October 17, 2016, the owner or operator of the CCR unit must compile a history of construction, which shall contain, to the extent feasible, the information specified in

paragraphs (c)(1)(i) through (xi) of this section.

(i) The name and address of the person(s) owning or operating the CCR unit; the name associated with the CCR unit; and the identification number of the CCR unit if one has been assigned by the state.

(ii) The location of the CCR unit identified on the most recent U.S. Geological Survey (USGS) 7½ minute or 15 minute topographic quadrangle map, or a topographic map of equivalent scale if a USGS map is not available.

(iii) A statement of the purpose for which the CCR unit is being used.

(iv) The name and size in acres of the watershed within which the CCR unit is located.

(v) A description of the physical and engineering properties of the foundation and abutment materials on which the CCR unit is constructed.

(vi) A statement of the type, size, range, and physical and engineering properties of the materials used in constructing each zone or stage of the CCR unit; the method of site preparation and construction of each zone of the CCR unit; and the approximate dates of construction of each successive stage of construction of the CCR unit.

(vii) At a scale that details engineering structures and appurtenances relevant to the design, construction, operation, and maintenance of the CCR unit, detailed dimensional drawings of the CCR unit, including a plan view and cross sections of the length and width of the CCR unit, showing all zones, foundation improvements, drainage provisions, spillways, diversion ditches, outlets, instrument locations, and slope protection, in addition to the normal operating pool surface elevation and the maximum pool surface elevation following peak discharge from the inflow design flood, the expected maximum depth of CCR within the CCR surface impoundment, and any identifiable natural or manmade features that could adversely affect operation of the CCR unit due to malfunction or mis-operation.

(viii) A description of the type, purpose, and location of existing instrumentation.

(ix) Area-capacity curves for the CCR unit.

(x) A description of each spillway and diversion design features and capacities and calculations used in their determination.

(xi) The construction specifications and provisions for surveillance, maintenance, and repair of the CCR unit.

(xii) Any record or knowledge of structural instability of the CCR unit.

(2) *Changes to the history of construction.* If there is a significant change to any information compiled under paragraph (c)(1) of this section, the owner or operator of the CCR unit must update the relevant information and place it in the facility's operating record as required by § 257.105(f)(9).

(d) *Periodic structural stability assessments.* (1) The owner or operator of the CCR unit must conduct initial and periodic structural stability assessments and document whether the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering practices for the maximum volume of CCR and CCR wastewater which can be impounded therein. The assessment must, at a minimum, document whether the CCR unit has been designed, constructed, operated, and maintained with:

(i) Stable foundations and abutments;

(ii) Adequate slope protection to protect against surface erosion, wave action, and adverse effects of sudden drawdown;

(iii) Dikes mechanically compacted to a density sufficient to withstand the range of loading conditions in the CCR unit;

(iv) Vegetated slopes of dikes and surrounding areas not to exceed a height of six inches above the slope of the dike, except for slopes which have an alternate form or forms of slope protection;

(v) A single spillway or a combination of spillways configured as specified in paragraph (d)(1)(v)(A) of this section. The combined capacity of all spillways must be designed, constructed, operated, and maintained to adequately manage flow during and following the peak discharge from the event specified in paragraph (d)(1)(v)(B) of this section.

(A) All spillways must be either:

(*1*) Of non-erodible construction and designed to carry sustained flows; or

(*2*) Earth- or grass-lined and designed to carry short-term, infrequent flows at non-erosive velocities where sustained flows are not expected.

(B) The combined capacity of all spillways must adequately manage flow during and following the peak discharge from a:

(*1*) Probable maximum flood (PMF) for a high hazard potential CCR surface impoundment; or

(*2*) 1000-year flood for a significant hazard potential CCR surface impoundment; or

(*3*) 100-year flood for a low hazard potential CCR surface impoundment.

(vi) Hydraulic structures underlying the base of the CCR unit or passing through the dike of the CCR unit that maintain structural integrity and are free of significant deterioration, deformation, distortion, bedding deficiencies, sedimentation, and debris which may negatively affect the operation of the hydraulic structure; and

(vii) For CCR units with downstream slopes which can be inundated by the pool of an adjacent water body, such as a river, stream or lake, downstream slopes that maintain structural stability during low pool of the adjacent water body or sudden drawdown of the adjacent water body.

(2) The periodic assessment described in paragraph (d)(1) of this section must identify any structural stability deficiencies associated with the CCR unit in addition to recommending corrective measures. If a deficiency or a release is identified during the periodic assessment, the owner or operator unit must remedy the deficiency or release as soon as feasible and prepare documentation detailing the corrective measures taken.

(3) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial assessment and each subsequent periodic assessment was conducted in accordance with the requirements of this section.

(e) *Periodic safety factor assessments.* (1) The owner or operator must conduct an initial and periodic safety factor assessments for each CCR unit and document whether the calculated factors of safety for each CCR unit achieve the minimum safety factors specified in paragraphs (e)(1)(i) through (iv) of this section for the critical cross section of the embankment. The critical cross section is the cross section anticipated to be the most susceptible of all cross sections to structural failure based on appropriate engineering considerations, including loading conditions. The safety factor assessments must be supported by appropriate engineering calculations.

(i) The calculated static factor of safety under the long-term, maximum storage pool loading condition must equal or exceed 1.50.

(ii) The calculated static factor of safety under the maximum surcharge pool loading condition must equal or exceed 1.40.

(iii) The calculated seismic factor of safety must equal or exceed 1.00.

(iv) For dikes constructed of soils that have susceptibility to liquefaction, the calculated liquefaction factor of safety must equal or exceed 1.20.

(2) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating

that the initial assessment and each subsequent periodic assessment specified in paragraph (e)(1) of this section meets the requirements of this section.

(f) *Timeframes for periodic assessments*—(1) *Initial assessments.* Except as provided by paragraph (f)(2) of this section, the owner or operator of the CCR unit must complete the initial assessments required by paragraphs (a)(2), (d), and (e) of this section no later than October 17, 2016. The owner or operator has completed an initial assessment when the owner or operator has placed the assessment required by paragraphs (a)(2), (d), and (e) of this section in the facility's operating record as required by § 257.105(f)(5), (10), and (12).

(2) *Use of a previously completed assessment(s) in lieu of the initial assessment(s).* The owner or operator of the CCR unit may elect to use a previously completed assessment to serve as the initial assessment required by paragraphs (a)(2), (d), and (e) of this section provided that the previously completed assessment(s):

(i) Was completed no earlier than 42 months prior to October 17, 2016; and

(ii) Meets the applicable requirements of paragraphs (a)(2), (d), and (e) of this section.

(3) *Frequency for conducting periodic assessments.* The owner or operator of the CCR unit must conduct and complete the assessments required by paragraphs (a)(2), (d), and (e) of this section every five years. The date of completing the initial assessment is the basis for establishing the deadline to complete the first subsequent assessment. If the owner or operator elects to use a previously completed assessment(s) in lieu of the initial assessment as provided by paragraph (f)(2) of this section, the date of the report for the previously completed assessment is the basis for establishing the deadline to complete the first subsequent assessment. The owner or operator may complete any required assessment prior to the required deadline provided the owner or operator places the completed assessment(s) into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing subsequent assessments is based on the date of completing the previous assessment. For purposes of this paragraph (f)(3), the owner or operator has completed an assessment when the relevant assessment(s) required by paragraphs (a)(2), (d), and (e) of this section has been placed in the facility's operating record as required by § 257.105(f)(5), (10), and (12).

(4) *Closure of the CCR unit.* An owner or operator of a CCR unit who either fails to complete a timely safety factor assessment or fails to demonstrate minimum safety factors as required by paragraph (e) of this section is subject to the requirements of § 257.101(b)(2).

(g) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the internet requirements specified in § 257.107(f).

§ 257.74 Structural integrity criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment.

(a) The requirements of paragraphs (a)(1) through (4) of this section apply to all new CCR surface impoundments and any lateral expansion of a CCR surface impoundment, except for those new CCR surface impoundments that are incised CCR units. If an incised CCR surface impoundment is subsequently modified (*e.g.,* a dike is constructed) such that the CCR unit no longer meets the definition of an incised CCR unit, the CCR unit is subject to the requirements of paragraphs (a)(1) through (4) of this section.

(1) No later than the initial receipt of CCR, the owner or operator of the CCR unit must place on or immediately adjacent to the CCR unit a permanent identification marker, at least six feet high showing the identification number of the CCR unit, if one has been assigned by the state, the name associated with the CCR unit and the name of the owner or operator of the CCR unit.

(2) *Periodic hazard potential classification assessments.* (i) The owner or operator of the CCR unit must conduct initial and periodic hazard potential classification assessments of the CCR unit according to the timeframes specified in paragraph (f) of this section. The owner or operator must document the hazard potential classification of each CCR unit as either a high hazard potential CCR surface impoundment, a significant hazard potential CCR surface impoundment, or a low hazard potential CCR surface impoundment. The owner or operator must also document the basis for each hazard potential classification.

(ii) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial hazard potential classification and each subsequent periodic classification specified in paragraph (a)(2)(i) of this section was conducted in accordance with the requirements of this section.

(3) *Emergency Action Plan (EAP)*—(i) *Development of the plan.* Prior to the initial receipt of CCR in the CCR unit, the owner or operator of a CCR unit determined to be either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment under paragraph (a)(2) of this section must prepare and maintain a written EAP. At a minimum, the EAP must:

(A) Define the events or circumstances involving the CCR unit that represent a safety emergency, along with a description of the procedures that will be followed to detect a safety emergency in a timely manner;

(B) Define responsible persons, their respective responsibilities, and notification procedures in the event of a safety emergency involving the CCR unit;

(C) Provide contact information of emergency responders;

(D) Include a map which delineates the downstream area which would be affected in the event of a CCR unit failure and a physical description of the CCR unit; and

(E) Include provisions for an annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders.

(ii) *Amendment of the plan.* (A) The owner or operator of a CCR unit subject to the requirements of paragraph (a)(3)(i) of this section may amend the written EAP at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(f)(6). The owner or operator must amend the written EAP whenever there is a change in conditions that would substantially affect the EAP in effect.

(B) The written EAP must be evaluated, at a minimum, every five years to ensure the information required in paragraph (a)(3)(i) of this section is accurate. As necessary, the EAP must be updated and a revised EAP placed in the facility's operating record as required by § 257.105(f)(6).

(iii) *Changes in hazard potential classification.* (A) If the owner or operator of a CCR unit determines during a periodic hazard potential assessment that the CCR unit is no longer classified as either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment, then the owner or operator of the CCR unit is no longer subject to the requirement to prepare and maintain a written EAP beginning on the date the periodic hazard potential assessment documentation is

placed in the facility's operating record as required by § 257.105(f)(5).

(B) If the owner or operator of a CCR unit classified as a low hazard potential CCR surface impoundment subsequently determines that the CCR unit is properly re-classified as either a high hazard potential CCR surface impoundment or a significant hazard potential CCR surface impoundment, then the owner or operator of the CCR unit must prepare a written EAP for the CCR unit as required by paragraph (a)(3)(i) of this section within six months of completing such periodic hazard potential assessment.

(iv) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the written EAP, and any subsequent amendment of the EAP, meets the requirements of paragraph (a)(3) of this section.

(v) *Activation of the EAP.* The EAP must be implemented once events or circumstances involving the CCR unit that represent a safety emergency are detected, including conditions identified during periodic structural stability assessments, annual inspections, and inspections by a qualified person.

(4) The CCR unit and surrounding areas must be designed, constructed, operated, and maintained with vegetated slopes of dikes not to exceed a height of six inches above the slope of the dike, except for slopes which are protected with an alternate form(s) of slope protection.

(b) The requirements of paragraphs (c) through (e) of this section apply to an owner or operator of a new CCR surface impoundment and any lateral expansion of a CCR surface impoundment that either:

(1) Has a height of five feet or more and a storage volume of 20 acre-feet or more; or

(2) Has a height of 20 feet or more.

(c)(1) No later than the initial receipt of CCR in the CCR unit, the owner or operator unit must compile the design and construction plans for the CCR unit, which must include, to the extent feasible, the information specified in paragraphs (c)(1)(i) through (xi) of this section.

(i) The name and address of the person(s) owning or operating the CCR unit; the name associated with the CCR unit; and the identification number of the CCR unit if one has been assigned by the state.

(ii) The location of the CCR unit identified on the most recent U.S. Geological Survey (USGS) 7½ minute or 15 minute topographic quadrangle map, or a topographic map of equivalent scale if a USGS map is not available.

(iii) A statement of the purpose for which the CCR unit is being used.

(iv) The name and size in acres of the watershed within which the CCR unit is located.

(v) A description of the physical and engineering properties of the foundation and abutment materials on which the CCR unit is constructed.

(vi) A statement of the type, size, range, and physical and engineering properties of the materials used in constructing each zone or stage of the CCR unit; the method of site preparation and construction of each zone of the CCR unit; and the dates of construction of each successive stage of construction of the CCR unit.

(vii) At a scale that details engineering structures and appurtenances relevant to the design, construction, operation, and maintenance of the CCR unit, detailed dimensional drawings of the CCR unit, including a plan view and cross sections of the length and width of the CCR unit, showing all zones, foundation improvements, drainage provisions, spillways, diversion ditches, outlets, instrument locations, and slope protection, in addition to the normal operating pool surface elevation and the maximum pool surface elevation following peak discharge from the inflow design flood, the expected maximum depth of CCR within the CCR surface impoundment, and any identifiable natural or manmade features that could adversely affect operation of the CCR unit due to malfunction or mis-operation.

(viii) A description of the type, purpose, and location of existing instrumentation.

(ix) Area-capacity curves for the CCR unit.

(x) A description of each spillway and diversion design features and capacities and calculations used in their determination.

(xi) The construction specifications and provisions for surveillance, maintenance, and repair of the CCR unit.

(xii) Any record or knowledge of structural instability of the CCR unit.

(2) *Changes in the design and construction.* If there is a significant change to any information compiled under paragraph (c)(1) of this section, the owner or operator of the CCR unit must update the relevant information and place it in the facility's operating record as required by § 257.105(f)(13).

(d) *Periodic structural stability assessments.* (1) The owner or operator of the CCR unit must conduct initial and periodic structural stability assessments and document whether the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering practices for the maximum volume of CCR and CCR wastewater which can be impounded therein. The assessment must, at a minimum, document whether the CCR unit has been designed, constructed, operated, and maintained with:

(i) Stable foundations and abutments;

(ii) Adequate slope protection to protect against surface erosion, wave action, and adverse effects of sudden drawdown;

(iii) Dikes mechanically compacted to a density sufficient to withstand the range of loading conditions in the CCR unit;

(iv) Vegetated slopes of dikes and surrounding areas not to exceed a height of six inches above the slope of the dike, except for slopes which have an alternate form or forms of slope protection;

(v) A single spillway or a combination of spillways configured as specified in paragraph (d)(1)(v)(A) of this section. The combined capacity of all spillways must be designed, constructed, operated, and maintained to adequately manage flow during and following the peak discharge from the event specified in paragraph (d)(1)(v)(B) of this section.

(A) All spillways must be either:

(*1*) Of non-erodible construction and designed to carry sustained flows; or

(*2*) Earth- or grass-lined and designed to carry short-term, infrequent flows at non-erosive velocities where sustained flows are not expected.

(B) The combined capacity of all spillways must adequately manage flow during and following the peak discharge from a:

(*1*) Probable maximum flood (PMF) for a high hazard potential CCR surface impoundment; or

(*2*) 1000-year flood for a significant hazard potential CCR surface impoundment; or

(*3*) 100-year flood for a low hazard potential CCR surface impoundment.

(vi) Hydraulic structures underlying the base of the CCR unit or passing through the dike of the CCR unit that maintain structural integrity and are free of significant deterioration, deformation, distortion, bedding deficiencies, sedimentation, and debris which may negatively affect the operation of the hydraulic structure; and

(vii) For CCR units with downstream slopes which can be inundated by the pool of an adjacent water body, such as a river, stream or lake, downstream slopes that maintain structural stability

during low pool of the adjacent water body or sudden drawdown of the adjacent water body.

(2) The periodic assessment described in paragraph (d)(1) of this section must identify any structural stability deficiencies associated with the CCR unit in addition to recommending corrective measures. If a deficiency or a release is identified during the periodic assessment, the owner or operator unit must remedy the deficiency or release as soon as feasible and prepare documentation detailing the corrective measures taken.

(3) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial assessment and each subsequent periodic assessment was conducted in accordance with the requirements of this section.

(e) *Periodic safety factor assessments.* (1) The owner or operator must conduct an initial and periodic safety factor assessments for each CCR unit and document whether the calculated factors of safety for each CCR unit achieve the minimum safety factors specified in paragraphs (e)(1)(i) through (v) of this section for the critical cross section of the embankment. The critical cross section is the cross section anticipated to be the most susceptible of all cross sections to structural failure based on appropriate engineering considerations, including loading conditions. The safety factor assessments must be supported by appropriate engineering calculations.

(i) The calculated static factor of safety under the end-of-construction loading condition must equal or exceed 1.30. The assessment of this loading condition is only required for the initial safety factor assessment and is not required for subsequent assessments.

(ii) The calculated static factor of safety under the long-term, maximum storage pool loading condition must equal or exceed 1.50.

(iii) The calculated static factor of safety under the maximum surcharge pool loading condition must equal or exceed 1.40.

(iv) The calculated seismic factor of safety must equal or exceed 1.00.

(v) For dikes constructed of soils that have susceptibility to liquefaction, the calculated liquefaction factor of safety must equal or exceed 1.20.

(2) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the initial assessment and each subsequent periodic assessment specified in paragraph (e)(1) of this section meets the requirements of this section.

(f) *Timeframes for periodic assessments*—(1) *Initial assessments.* Except as provided by paragraph (f)(2) of this section, the owner or operator of the CCR unit must complete the initial assessments required by paragraphs (a)(2), (d), and (e) of this section prior to the initial receipt of CCR in the unit. The owner or operator has completed an initial assessment when the owner or operator has placed the assessment required by paragraphs (a)(2), (d), and (e) of this section in the facility's operating record as required by § 257.105(f)(5), (10), and (12).

(2) *Frequency for conducting periodic assessments.* The owner or operator of the CCR unit must conduct and complete the assessments required by paragraphs (a)(2), (d), and (e) of this section every five years. The date of completing the initial assessment is the basis for establishing the deadline to complete the first subsequent assessment. The owner or operator may complete any required assessment prior to the required deadline provided the owner or operator places the completed assessment(s) into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing subsequent assessments is based on the date of completing the previous assessment. For purposes of this paragraph (f)(2), the owner or operator has completed an assessment when the relevant assessment(s) required by paragraphs (a)(2), (d), and (e) of this section has been placed in the facility's operating record as required by § 257.105(f)(5), (10), and (12).

(3) *Failure to document minimum safety factors during the initial assessment.* Until the date an owner or operator of a CCR unit documents that the calculated factors of safety achieve the minimum safety factors specified in paragraphs (e)(1)(i) through (v) of this section, the owner or operator is prohibited from placing CCR in such unit.

(4) *Closure of the CCR unit.* An owner or operator of a CCR unit who either fails to complete a timely periodic safety factor assessment or fails to demonstrate minimum safety factors as required by paragraph (e) of this section is subject to the requirements of § 257.101(c).

(g) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(f), the notification requirements specified in § 257.106(f), and the internet requirements specified in § 257.107(f).

Operating Criteria

§ 257.80 Air criteria.

(a) The owner or operator of a CCR landfill, CCR surface impoundment, or any lateral expansion of a CCR unit must adopt measures that will effectively minimize CCR from becoming airborne at the facility, including CCR fugitive dust originating from CCR units, roads, and other CCR management and material handling activities.

(b) *CCR fugitive dust control plan.* The owner or operator of the CCR unit must prepare and operate in accordance with a CCR fugitive dust control plan as specified in paragraphs (b)(1) through (7) of this section. This requirement applies in addition to, not in place of, any applicable standards under the Occupational Safety and Health Act.

(1) The CCR fugitive dust control plan must identify and describe the CCR fugitive dust control measures the owner or operator will use to minimize CCR from becoming airborne at the facility. The owner or operator must select, and include in the CCR fugitive dust control plan, the CCR fugitive dust control measures that are most appropriate for site conditions, along with an explanation of how the measures selected are applicable and appropriate for site conditions. Examples of control measures that may be appropriate include: Locating CCR inside an enclosure or partial enclosure; operating a water spray or fogging system; reducing fall distances at material drop points; using wind barriers, compaction, or vegetative covers; establishing and enforcing reduced vehicle speed limits; paving and sweeping roads; covering trucks transporting CCR; reducing or halting operations during high wind events; or applying a daily cover.

(2) If the owner or operator operates a CCR landfill or any lateral expansion of a CCR landfill, the CCR fugitive dust control plan must include procedures to emplace CCR as conditioned CCR. Conditioned CCR means wetting CCR with water to a moisture content that will prevent wind dispersal, but will not result in free liquids. In lieu of water, CCR conditioning may be accomplished with an appropriate chemical dust suppression agent.

(3) The CCR fugitive dust control plan must include procedures to log citizen complaints received by the owner or operator involving CCR fugitive dust events at the facility.

(4) The CCR fugitive dust control plan must include a description of the procedures the owner or operator will

follow to periodically assess the effectiveness of the control plan.

(5) The owner or operator of a CCR unit must prepare an initial CCR fugitive dust control plan for the facility no later than October 19, 2015, or by initial receipt of CCR in any CCR unit at the facility if the owner or operator becomes subject to this subpart after October 19, 2015. The owner or operator has completed the initial CCR fugitive dust control plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(1).

(6) *Amendment of the plan.* The owner or operator of a CCR unit subject to the requirements of this section may amend the written CCR fugitive dust control plan at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(g)(1). The owner or operator must amend the written plan whenever there is a change in conditions that would substantially affect the written plan in effect, such as the construction and operation of a new CCR unit.

(7) The owner or operator must obtain a certification from a qualified professional engineer that the initial CCR fugitive dust control plan, or any subsequent amendment of it, meets the requirements of this section.

(c) *Annual CCR fugitive dust control report.* The owner or operator of a CCR unit must prepare an annual CCR fugitive dust control report that includes a description of the actions taken by the owner or operator to control CCR fugitive dust, a record of all citizen complaints, and a summary of any corrective measures taken. The initial annual report must be completed no later than 14 months after placing the initial CCR fugitive dust control plan in the facility's operating record. The deadline for completing a subsequent report is one year after the date of completing the previous report. For purposes of this paragraph (c), the owner or operator has completed the annual CCR fugitive dust control report when the plan has been placed in the facility's operating record as required by § 257.105(g)(2).

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

§ 257.81 Run-on and run-off controls for CCR landfills.

(a) The owner or operator of an existing or new CCR landfill or any lateral expansion of a CCR landfill must design, construct, operate, and maintain:

(1) A run-on control system to prevent flow onto the active portion of the CCR unit during the peak discharge from a 24-hour, 25-year storm; and

(2) A run-off control system from the active portion of the CCR unit to collect and control at least the water volume resulting from a 24-hour, 25-year storm.

(b) Run-off from the active portion of the CCR unit must be handled in accordance with the surface water requirements under § 257.3–3.

(c) *Run-on and run-off control system plan*—(1) *Content of the plan.* The owner or operator must prepare initial and periodic run-on and run-off control system plans for the CCR unit according to the timeframes specified in paragraphs (c)(3) and (4) of this section. These plans must document how the run-on and run-off control systems have been designed and constructed to meet the applicable requirements of this section. Each plan must be supported by appropriate engineering calculations. The owner or operator has completed the initial run-on and run-off control system plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(3).

(2) *Amendment of the plan.* The owner or operator may amend the written run-on and run-off control system plan at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(g)(3). The owner or operator must amend the written run-on and run-off control system plan whenever there is a change in conditions that would substantially affect the written plan in effect.

(3) *Timeframes for preparing the initial plan*—(i) *Existing CCR landfills.* The owner or operator of the CCR unit must prepare the initial run-on and run-off control system plan no later than October 17, 2016.

(ii) *New CCR landfills and any lateral expansion of a CCR landfill.* The owner or operator must prepare the initial run-on and run-off control system plan no later than the date of initial receipt of CCR in the CCR unit.

(4) *Frequency for revising the plan.* The owner or operator of the CCR unit must prepare periodic run-on and run-off control system plans required by paragraph (c)(1) of this section every five years. The date of completing the initial plan is the basis for establishing the deadline to complete the first subsequent plan. The owner or operator may complete any required plan prior to the required deadline provided the owner or operator places the completed plan into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing a subsequent plan is based on the date of completing the previous plan. For purposes of this paragraph (c)(4), the owner or operator has completed a periodic run-on and run-off control system plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(3).

(5) The owner or operator must obtain a certification from a qualified professional engineer stating that the initial and periodic run-on and run-off control system plans meet the requirements of this section.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

§ 257.82 Hydrologic and hydraulic capacity requirements for CCR surface impoundments.

(a) The owner or operator of an existing or new CCR surface impoundment or any lateral expansion of a CCR surface impoundment must design, construct, operate, and maintain an inflow design flood control system as specified in paragraphs (a)(1) and (2) of this section.

(1) The inflow design flood control system must adequately manage flow into the CCR unit during and following the peak discharge of the inflow design flood specified in paragraph (a)(3) of this section.

(2) The inflow design flood control system must adequately manage flow from the CCR unit to collect and control the peak discharge resulting from the inflow design flood specified in paragraph (a)(3) of this section.

(3) The inflow design flood is:

(i) For a high hazard potential CCR surface impoundment, as determined under § 257.73(a)(2) or § 257.74(a)(2), the probable maximum flood;

(ii) For a significant hazard potential CCR surface impoundment, as determined under § 257.73(a)(2) or § 257.74(a)(2), the 1,000-year flood;

(iii) For a low hazard potential CCR surface impoundment, as determined under § 257.73(a)(2) or § 257.74(a)(2), the 100-year flood; or

(iv) For an incised CCR surface impoundment, the 25-year flood.

(b) Discharge from the CCR unit must be handled in accordance with the surface water requirements under § 257.3–3.

(c) *Inflow design flood control system plan*—(1) *Content of the plan.* The owner or operator must prepare initial

and periodic inflow design flood control system plans for the CCR unit according to the timeframes specified in paragraphs (c)(3) and (4) of this section. These plans must document how the inflow design flood control system has been designed and constructed to meet the requirements of this section. Each plan must be supported by appropriate engineering calculations. The owner or operator of the CCR unit has completed the inflow design flood control system plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(4).

(2) *Amendment of the plan.* The owner or operator of the CCR unit may amend the written inflow design flood control system plan at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(g)(4). The owner or operator must amend the written inflow design flood control system plan whenever there is a change in conditions that would substantially affect the written plan in effect.

(3) *Timeframes for preparing the initial plan*—(i) *Existing CCR surface impoundments.* The owner or operator of the CCR unit must prepare the initial inflow design flood control system plan no later than October 17, 2016.

(ii) *New CCR surface impoundments and any lateral expansion of a CCR surface impoundment.* The owner or operator must prepare the initial inflow design flood control system plan no later than the date of initial receipt of CCR in the CCR unit.

(4) *Frequency for revising the plan.* The owner or operator must prepare periodic inflow design flood control system plans required by paragraph (c)(1) of this section every five years. The date of completing the initial plan is the basis for establishing the deadline to complete the first periodic plan. The owner or operator may complete any required plan prior to the required deadline provided the owner or operator places the completed plan into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing a subsequent plan is based on the date of completing the previous plan. For purposes of this paragraph (c)(4), the owner or operator has completed an inflow design flood control system plan when the plan has been placed in the facility's operating record as required by § 257.105(g)(4).

(5) The owner or operator must obtain a certification from a qualified professional engineer stating that the initial and periodic inflow design flood control system plans meet the requirements of this section.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

§ 257.83 Inspection requirements for CCR surface impoundments.

(a) *Inspections by a qualified person.* (1) All CCR surface impoundments and any lateral expansion of a CCR surface impoundment must be examined by a qualified person as follows:

(i) At intervals not exceeding seven days, inspect for any appearances of actual or potential structural weakness and other conditions which are disrupting or have the potential to disrupt the operation or safety of the CCR unit;

(ii) At intervals not exceeding seven days, inspect the discharge of all outlets of hydraulic structures which pass underneath the base of the surface impoundment or through the dike of the CCR unit for abnormal discoloration, flow or discharge of debris or sediment; and

(iii) At intervals not exceeding 30 days, monitor all CCR unit instrumentation.

(iv) The results of the inspection by a qualified person must be recorded in the facility's operating record as required by § 257.105(g)(5).

(2) *Timeframes for inspections by a qualified person*—(i) *Existing CCR surface impoundments.* The owner or operator of the CCR unit must initiate the inspections required under paragraph (a) of this section no later than October 19, 2015.

(ii) *New CCR surface impoundments and any lateral expansion of a CCR surface impoundment.* The owner or operator of the CCR unit must initiate the inspections required under paragraph (a) of this section upon initial receipt of CCR by the CCR unit.

(b) Annual i*nspections by a qualified professional engineer.* (1) If the existing or new CCR surface impoundment or any lateral expansion of the CCR surface impoundment is subject to the periodic structural stability assessment requirements under § 257.73(d) or § 257.74(d), the CCR unit must additionally be inspected on a periodic basis by a qualified professional engineer to ensure that the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering standards. The inspection must, at a minimum, include:

(i) A review of available information regarding the status and condition of the CCR unit, including, but not limited to, files available in the operating record (*e.g.,* CCR unit design and construction information required by §§ 257.73(c)(1) and 257.74(c)(1), previous periodic structural stability assessments required under §§ 257.73(d) and 257.74(d), the results of inspections by a qualified person, and results of previous annual inspections);

(ii) A visual inspection of the CCR unit to identify signs of distress or malfunction of the CCR unit and appurtenant structures; and

(iii) A visual inspection of any hydraulic structures underlying the base of the CCR unit or passing through the dike of the CCR unit for structural integrity and continued safe and reliable operation.

(2) *Inspection report.* The qualified professional engineer must prepare a report following each inspection that addresses the following:

(i) Any changes in geometry of the impounding structure since the previous annual inspection;

(ii) The location and type of existing instrumentation and the maximum recorded readings of each instrument since the previous annual inspection;

(iii) The approximate minimum, maximum, and present depth and elevation of the impounded water and CCR since the previous annual inspection;

(iv) The storage capacity of the impounding structure at the time of the inspection;

(v) The approximate volume of the impounded water and CCR at the time of the inspection;

(vi) Any appearances of an actual or potential structural weakness of the CCR unit, in addition to any existing conditions that are disrupting or have the potential to disrupt the operation and safety of the CCR unit and appurtenant structures; and

(vii) Any other change(s) which may have affected the stability or operation of the impounding structure since the previous annual inspection.

(3) *Timeframes for conducting the initial inspection*—(i) *Existing CCR surface impoundments.* The owner or operator of the CCR unit must complete the initial inspection required by paragraphs (b)(1) and (2) of this section no later than January 18, 2016.

(ii) *New CCR surface impoundments and any lateral expansion of a CCR surface impoundment.* The owner or operator of the CCR unit must complete the initial annual inspection required by paragraphs (b)(1) and (2) of this section is completed no later than 14 months

following the date of initial receipt of CCR in the CCR unit.

(4) *Frequency of inspections.* (i) Except as provided for in paragraph (b)(4)(ii) of this section, the owner or operator of the CCR unit must conduct the inspection required by paragraphs (b)(1) and (2) of this section on an annual basis. The date of completing the initial inspection report is the basis for establishing the deadline to complete the first subsequent inspection. Any required inspection may be conducted prior to the required deadline provided the owner or operator places the completed inspection report into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing subsequent inspection reports is based on the date of completing the previous inspection report. For purposes of this section, the owner or operator has completed an inspection when the inspection report has been placed in the facility's operating record as required by § 257.105(g)(6).

(ii) In any calendar year in which both the periodic inspection by a qualified professional engineer and the quinquennial (occurring every five years) structural stability assessment by a qualified professional engineer required by §§ 257.73(d) and 257.74(d) are required to be completed, the annual inspection is not required, provided the structural stability assessment is completed during the calendar year. If the annual inspection is not conducted in a year as provided by this paragraph (b)(4)(ii), the deadline for completing the next annual inspection is one year from the date of completing the quinquennial structural stability assessment.

(5) If a deficiency or release is identified during an inspection, the owner or operator must remedy the deficiency or release as soon as feasible and prepare documentation detailing the corrective measures taken.

(c) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

§ 257.84 Inspection requirements for CCR landfills.

(a) *Inspections by a qualified person.* (1) All CCR landfills and any lateral expansion of a CCR landfill must be examined by a qualified person as follows:

(i) At intervals not exceeding seven days, inspect for any appearances of actual or potential structural weakness and other conditions which are disrupting or have the potential to disrupt the operation or safety of the CCR unit; and

(ii) The results of the inspection by a qualified person must be recorded in the facility's operating record as required by § 257.105(g)(8).

(2) *Timeframes for inspections by a qualified person*—(i) *Existing CCR landfills.* The owner or operator of the CCR unit must initiate the inspections required under paragraph (a) of this section no later than October 19, 2015.

(ii) *New CCR landfills and any lateral expansion of a CCR landfill.* The owner or operator of the CCR unit must initiate the inspections required under paragraph (a) of this section upon initial receipt of CCR by the CCR unit.

(b) *Annual inspections by a qualified professional engineer.* (1) Existing and new CCR landfills and any lateral expansion of a CCR landfill must be inspected on a periodic basis by a qualified professional engineer to ensure that the design, construction, operation, and maintenance of the CCR unit is consistent with recognized and generally accepted good engineering standards. The inspection must, at a minimum, include:

(i) A review of available information regarding the status and condition of the CCR unit, including, but not limited to, files available in the operating record (*e.g.,* the results of inspections by a qualified person, and results of previous annual inspections); and

(ii) A visual inspection of the CCR unit to identify signs of distress or malfunction of the CCR unit.

(2) *Inspection report.* The qualified professional engineer must prepare a report following each inspection that addresses the following:

(i) Any changes in geometry of the structure since the previous annual inspection;

(ii) The approximate volume of CCR contained in the unit at the time of the inspection;

(iii) Any appearances of an actual or potential structural weakness of the CCR unit, in addition to any existing conditions that are disrupting or have the potential to disrupt the operation and safety of the CCR unit; and

(iv) Any other change(s) which may have affected the stability or operation of the CCR unit since the previous annual inspection.

(3) *Timeframes for conducting the initial inspection*—(i) *Existing CCR landfills.* The owner or operator of the CCR unit must complete the initial inspection required by paragraphs (b)(1) and (2) of this section no later than January 18, 2016.

(ii) *New CCR landfills and any lateral expansion of a CCR landfill.* The owner or operator of the CCR unit must complete the initial annual inspection required by paragraphs (b)(1) and (2) of this section no later than 14 months following the date of initial receipt of CCR in the CCR unit.

(4) *Frequency of inspections.* The owner or operator of the CCR unit must conduct the inspection required by paragraphs (b)(1) and (2) of this section on an annual basis. The date of completing the initial inspection report is the basis for establishing the deadline to complete the first subsequent inspection. Any required inspection may be conducted prior to the required deadline provided the owner or operator places the completed inspection report into the facility's operating record within a reasonable amount of time. In all cases, the deadline for completing subsequent inspection reports is based on the date of completing the previous inspection report. For purposes of this section, the owner or operator has completed an inspection when the inspection report has been placed in the facility's operating record as required by § 257.105(g)(9).

(5) If a deficiency or release is identified during an inspection, the owner or operator must remedy the deficiency or release as soon as feasible and prepare documentation detailing the corrective measures taken.

(c) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

Groundwater Monitoring and Corrective Action

§ 257.90 Applicability.

(a) Except as provided for in § 257.100 for inactive CCR surface impoundments, all CCR landfills, CCR surface impoundments, and lateral expansions of CCR units are subject to the groundwater monitoring and corrective action requirements under §§ 257.90 through 257.98.

(b) *Initial timeframes*—(1) *Existing CCR landfills and existing CCR surface impoundments.* No later than October 17, 2017, the owner or operator of the CCR unit must be in compliance with the following groundwater monitoring requirements:

(i) Install the groundwater monitoring system as required by § 257.91;

(ii) Develop the groundwater sampling and analysis program to include selection of the statistical

procedures to be used for evaluating groundwater monitoring data as required by § 257.93;

(iii) Initiate the detection monitoring program to include obtaining a minimum of eight independent samples for each background and downgradient well as required by § 257.94(b); and

(iv) Begin evaluating the groundwater monitoring data for statistically significant increases over background levels for the constituents listed in appendix III of this part as required by § 257.94.

(2) *New CCR landfills, new CCR surface impoundments, and all lateral expansions of CCR units.* Prior to initial receipt of CCR by the CCR unit, the owner or operator must be in compliance with the groundwater monitoring requirements specified in paragraph (b)(1)(i) and (ii) of this section. In addition, the owner or operator of the CCR unit must initiate the detection monitoring program to include obtaining a minimum of eight independent samples for each background well as required by § 257.94(b).

(c) Once a groundwater monitoring system and groundwater monitoring program has been established at the CCR unit as required by this subpart, the owner or operator must conduct groundwater monitoring and, if necessary, corrective action throughout the active life and post-closure care period of the CCR unit.

(d) In the event of a release from a CCR unit, the owner or operator must immediately take all necessary measures to control the source(s) of releases so as to reduce or eliminate, to the maximum extent feasible, further releases of contaminants into the environment. The owner or operator of the CCR unit must comply with all applicable requirements in §§ 257.96, 257.97, and 257.98.

(e) *Annual groundwater monitoring and corrective action report.* For existing CCR landfills and existing CCR surface impoundments, no later than January 31, 2018, and annually thereafter, the owner or operator must prepare an annual groundwater monitoring and corrective action report. For new CCR landfills, new CCR surface impoundments, and all lateral expansions of CCR units, the owner or operator must prepare the initial annual groundwater monitoring and corrective action report no later than January 31 of the year following the calendar year a groundwater monitoring system has been established for such CCR unit as required by this subpart, and annually thereafter. For the preceding calendar year, the annual report must document the status of the groundwater monitoring and corrective action program for the CCR unit, summarize key actions completed, describe any problems encountered, discuss actions to resolve the problems, and project key activities for the upcoming year. For purposes of this section, the owner or operator has prepared the annual report when the report is placed in the facility's operating record as required by § 257.105(h)(1). At a minimum, the annual groundwater monitoring and corrective action report must contain the following information, to the extent available:

(1) A map, aerial image, or diagram showing the CCR unit and all background (or upgradient) and downgradient monitoring wells, to include the well identification numbers, that are part of the groundwater monitoring program for the CCR unit;

(2) Identification of any monitoring wells that were installed or decommissioned during the preceding year, along with a narrative description of why those actions were taken;

(3) In addition to all the monitoring data obtained under §§ 257.90 through 257.98, a summary including the number of groundwater samples that were collected for analysis for each background and downgradient well, the dates the samples were collected, and whether the sample was required by the detection monitoring or assessment monitoring programs;

(4) A narrative discussion of any transition between monitoring programs (*e.g.,* the date and circumstances for transitioning from detection monitoring to assessment monitoring in addition to identifying the constituent(s) detected at a statistically significant increase over background levels); and

(5) Other information required to be included in the annual report as specified in §§ 257.90 through 257.98.

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h).

§ 257.91 Groundwater monitoring systems.

(a) *Performance standard.* The owner or operator of a CCR unit must install a groundwater monitoring system that consists of a sufficient number of wells, installed at appropriate locations and depths, to yield groundwater samples from the uppermost aquifer that:

(1) Accurately represent the quality of background groundwater that has not been affected by leakage from a CCR unit. A determination of background quality may include sampling of wells that are not hydraulically upgradient of the CCR management area where:

(i) Hydrogeologic conditions do not allow the owner or operator of the CCR unit to determine what wells are hydraulically upgradient; or

(ii) Sampling at other wells will provide an indication of background groundwater quality that is as representative or more representative than that provided by the upgradient wells; and

(2) Accurately represent the quality of groundwater passing the waste boundary of the CCR unit. The downgradient monitoring system must be installed at the waste boundary that ensures detection of groundwater contamination in the uppermost aquifer. All potential contaminant pathways must be monitored.

(b) The number, spacing, and depths of monitoring systems shall be determined based upon site-specific technical information that must include thorough characterization of:

(1) Aquifer thickness, groundwater flow rate, groundwater flow direction including seasonal and temporal fluctuations in groundwater flow; and

(2) Saturated and unsaturated geologic units and fill materials overlying the uppermost aquifer, materials comprising the uppermost aquifer, and materials comprising the confining unit defining the lower boundary of the uppermost aquifer, including, but not limited to, thicknesses, stratigraphy, lithology, hydraulic conductivities, porosities and effective porosities.

(c) The groundwater monitoring system must include the minimum number of monitoring wells necessary to meet the performance standards specified in paragraph (a) of this section, based on the site-specific information specified in paragraph (b) of this section. The groundwater monitoring system must contain:

(1) A minimum of one upgradient and three downgradient monitoring wells; and

(2) Additional monitoring wells as necessary to accurately represent the quality of background groundwater that has not been affected by leakage from the CCR unit and the quality of groundwater passing the waste boundary of the CCR unit.

(d) The owner or operator of multiple CCR units may install a multiunit groundwater monitoring system instead of separate groundwater monitoring systems for each CCR unit.

(1) The multiunit groundwater monitoring system must be equally as capable of detecting monitored constituents at the waste boundary of

the CCR unit as the individual groundwater monitoring system specified in paragraphs (a) through (c) of this section for each CCR unit based on the following factors:

(i) Number, spacing, and orientation of each CCR unit;

(ii) Hydrogeologic setting;

(iii) Site history; and

(iv) Engineering design of the CCR unit.

(2) If the owner or operator elects to install a multiunit groundwater monitoring system, and if the multiunit system includes at least one existing unlined CCR surface impoundment as determined by § 257.71(a), and if at any time after October 19, 2015 the owner or operator determines in any sampling event that the concentrations of one or more constituents listed in appendix IV to this part are detected at statistically significant levels above the groundwater protection standard established under § 257.95(h) for the multiunit system, then all unlined CCR surface impoundments comprising the multiunit groundwater monitoring system are subject to the closure requirements under § 257.101(a) to retrofit or close.

(e) Monitoring wells must be cased in a manner that maintains the integrity of the monitoring well borehole. This casing must be screened or perforated and packed with gravel or sand, where necessary, to enable collection of groundwater samples. The annular space (*i.e.,* the space between the borehole and well casing) above the sampling depth must be sealed to prevent contamination of samples and the groundwater.

(1) The owner or operator of the CCR unit must document and include in the operating record the design, installation, development, and decommissioning of any monitoring wells, piezometers and other measurement, sampling, and analytical devices. The qualified professional engineer must be given access to this documentation when completing the groundwater monitoring system certification required under paragraph (f) of this section.

(2) The monitoring wells, piezometers, and other measurement, sampling, and analytical devices must be operated and maintained so that they perform to the design specifications throughout the life of the monitoring program.

(f) The owner or operator must obtain a certification from a qualified professional engineer stating that the groundwater monitoring system has been designed and constructed to meet the requirements of this section. If the groundwater monitoring system includes the minimum number of monitoring wells specified in paragraph (c)(1) of this section, the certification must document the basis supporting this determination.

(g) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h).

§ 257.92 [Reserved]

§ 257.93 Groundwater sampling and analysis requirements.

(a) The groundwater monitoring program must include consistent sampling and analysis procedures that are designed to ensure monitoring results that provide an accurate representation of groundwater quality at the background and downgradient wells required by § 257.91. The owner or operator of the CCR unit must develop a sampling and analysis program that includes procedures and techniques for:

(1) Sample collection;

(2) Sample preservation and shipment;

(3) Analytical procedures;

(4) Chain of custody control; and

(5) Quality assurance and quality control.

(b) The groundwater monitoring program must include sampling and analytical methods that are appropriate for groundwater sampling and that accurately measure hazardous constituents and other monitoring parameters in groundwater samples. For purposes of §§ 257.90 through 257.98, the term *constituent* refers to both hazardous constituents and other monitoring parameters listed in either appendix III or IV of this part.

(c) Groundwater elevations must be measured in each well immediately prior to purging, each time groundwater is sampled. The owner or operator of the CCR unit must determine the rate and direction of groundwater flow each time groundwater is sampled. Groundwater elevations in wells which monitor the same CCR management area must be measured within a period of time short enough to avoid temporal variations in groundwater flow which could preclude accurate determination of groundwater flow rate and direction.

(d) The owner or operator of the CCR unit must establish background groundwater quality in a hydraulically upgradient or background well(s) for each of the constituents required in the particular groundwater monitoring program that applies to the CCR unit as determined under § 257.94(a) or § 257.95(a). Background groundwater quality may be established at wells that are not located hydraulically upgradient from the CCR unit if it meets the requirements of § 257.91(a)(1).

(e) The number of samples collected when conducting detection monitoring and assessment monitoring (for both downgradient and background wells) must be consistent with the statistical procedures chosen under paragraph (f) of this section and the performance standards under paragraph (g) of this section. The sampling procedures shall be those specified under § 257.94(b) through (d) for detection monitoring, § 257.95(b) through (d) for assessment monitoring, and § 257.96(b) for corrective action.

(f) The owner or operator of the CCR unit must select one of the statistical methods specified in paragraphs (f)(1) through (5) of this section to be used in evaluating groundwater monitoring data for each specified constituent. The statistical test chosen shall be conducted separately for each constituent in each monitoring well.

(1) A parametric analysis of variance followed by multiple comparison procedures to identify statistically significant evidence of contamination. The method must include estimation and testing of the contrasts between each compliance well's mean and the background mean levels for each constituent.

(2) An analysis of variance based on ranks followed by multiple comparison procedures to identify statistically significant evidence of contamination. The method must include estimation and testing of the contrasts between each compliance well's median and the background median levels for each constituent.

(3) A tolerance or prediction interval procedure, in which an interval for each constituent is established from the distribution of the background data and the level of each constituent in each compliance well is compared to the upper tolerance or prediction limit.

(4) A control chart approach that gives control limits for each constituent.

(5) Another statistical test method that meets the performance standards of paragraph (g) of this section.

(6) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer stating that the selected statistical method is appropriate for evaluating the groundwater monitoring data for the CCR management area. The certification must include a narrative description of the statistical method selected to evaluate the groundwater monitoring data.

(g) Any statistical method chosen under paragraph (f) of this section shall comply with the following performance standards, as appropriate, based on the statistical test method used:

(1) The statistical method used to evaluate groundwater monitoring data shall be appropriate for the distribution of constituents. Normal distributions of data values shall use parametric methods. Non-normal distributions shall use non-parametric methods. If the distribution of the constituents is shown by the owner or operator of the CCR unit to be inappropriate for a normal theory test, then the data must be transformed or a distribution-free (non-parametric) theory test must be used. If the distributions for the constituents differ, more than one statistical method may be needed.

(2) If an individual well comparison procedure is used to compare an individual compliance well constituent concentration with background constituent concentrations or a groundwater protection standard, the test shall be done at a Type I error level no less than 0.01 for each testing period. If a multiple comparison procedure is used, the Type I experiment wise error rate for each testing period shall be no less than 0.05; however, the Type I error of no less than 0.01 for individual well comparisons must be maintained. This performance standard does not apply to tolerance intervals, prediction intervals, or control charts.

(3) If a control chart approach is used to evaluate groundwater monitoring data, the specific type of control chart and its associated parameter values shall be such that this approach is at least as effective as any other approach in this section for evaluating groundwater data. The parameter values shall be determined after considering the number of samples in the background data base, the data distribution, and the range of the concentration values for each constituent of concern.

(4) If a tolerance interval or a predictional interval is used to evaluate groundwater monitoring data, the levels of confidence and, for tolerance intervals, the percentage of the population that the interval must contain, shall be such that this approach is at least as effective as any other approach in this section for evaluating groundwater data. These parameters shall be determined after considering the number of samples in the background data base, the data distribution, and the range of the concentration values for each constituent of concern.

(5) The statistical method must account for data below the limit of detection with one or more statistical procedures that shall at least as effective as any other approach in this section for evaluating groundwater data. Any practical quantitation limit that is used in the statistical method shall be the lowest concentration level that can be reliably achieved within specified limits of precision and accuracy during routine laboratory operating conditions that are available to the facility.

(6) If necessary, the statistical method must include procedures to control or correct for seasonal and spatial variability as well as temporal correlation in the data.

(h) The owner or operator of the CCR unit must determine whether or not there is a statistically significant increase over background values for each constituent required in the particular groundwater monitoring program that applies to the CCR unit, as determined under § 257.94(a) or § 257.95(a).

(1) In determining whether a statistically significant increase has occurred, the owner or operator must compare the groundwater quality of each constituent at each monitoring well designated pursuant to § 257.91(a)(2) or (d)(1) to the background value of that constituent, according to the statistical procedures and performance standards specified under paragraphs (f) and (g) of this section.

(2) Within 90 days after completing sampling and analysis, the owner or operator must determine whether there has been a statistically significant increase over background for any constituent at each monitoring well.

(i) The owner or operator must measure ''total recoverable metals'' concentrations in measuring groundwater quality. Measurement of total recoverable metals captures both the particulate fraction and dissolved fraction of metals in natural waters. Groundwater samples shall not be field-filtered prior to analysis.

(j) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

§ 257.94 Detection monitoring program.

(a) The owner or operator of a CCR unit must conduct detection monitoring at all groundwater monitoring wells consistent with this section. At a minimum, a detection monitoring program must include groundwater monitoring for all constituents listed in appendix III to this part.

(b) Except as provided in paragraph (d) of this section, the monitoring frequency for the constituents listed in appendix III to this part shall be at least semiannual during the active life of the CCR unit and the post-closure period. For existing CCR landfills and existing CCR surface impoundments, a minimum of eight independent samples from each background and downgradient well must be collected and analyzed for the constituents listed in appendix III and IV to this part no later than October 17, 2017. For new CCR landfills, new CCR surface impoundments, and all lateral expansions of CCR units, a minimum of eight independent samples for each background well must be collected and analyzed for the constituents listed in appendices III and IV to this part during the first six months of sampling.

(c) The number of samples collected and analyzed for each background well and downgradient well during subsequent semiannual sampling events must be consistent with § 257.93(e), and must account for any unique characteristics of the site, but must be at least one sample from each background and downgradient well.

(d) The owner or operator of a CCR unit may demonstrate the need for an alternative monitoring frequency for repeated sampling and analysis for constituents listed in appendix III to this part during the active life and the post-closure care period based on the availability of groundwater. If there is not adequate groundwater flow to sample wells semiannually, the alternative frequency shall be no less than annual. The need to vary monitoring frequency must be evaluated on a site-specific basis. The demonstration must be supported by, at a minimum, the information specified in paragraphs (d)(1) and (2) of this section.

(1) Information documenting that the need for less frequent sampling. The alternative frequency must be based on consideration of the following factors:

(i) Lithology of the aquifer and unsaturated zone;

(ii) Hydraulic conductivity of the aquifer and unsaturated zone; and

(iii) Groundwater flow rates.

(2) Information documenting that the alternative frequency will be no less effective in ensuring that any leakage from the CCR unit will be discovered within a timeframe that will not materially delay establishment of an assessment monitoring program.

(3) The owner or operator must obtain a certification from a qualified

professional engineer stating that the demonstration for an alternative groundwater sampling and analysis frequency meets the requirements of this section. The owner or operator must include the demonstration providing the basis for the alternative monitoring frequency and the certification by a qualified professional engineer in the annual groundwater monitoring and corrective action report required by § 257.90(e).

(e) If the owner or operator of the CCR unit determines, pursuant to § 257.93(h) that there is a statistically significant increase over background levels for one or more of the constituents listed in appendix III to this part at any monitoring well at the waste boundary specified under § 257.91(a)(2), the owner or operator must:

(1) Except as provided for in paragraph (e)(2) of this section, within 90 days of detecting a statistically significant increase over background levels for any constituent, establish an assessment monitoring program meeting the requirements of § 257.95.

(2) The owner or operator may demonstrate that a source other than the CCR unit caused the statistically significant increase over background levels for a constituent or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality. The owner or operator must complete the written demonstration within 90 days of detecting a statistically significant increase over background levels to include obtaining a certification from a qualified professional engineer verifying the accuracy of the information in the report. If a successful demonstration is completed within the 90-day period, the owner or operator of the CCR unit may continue with a detection monitoring program under this section. If a successful demonstration is not completed within the 90-day period, the owner or operator of the CCR unit must initiate an assessment monitoring program as required under § 257.95. The owner or operator must also include the demonstration in the annual groundwater monitoring and corrective action report required by § 257.90(e), in addition to the certification by a qualified professional engineer.

(3) The owner or operator of a CCR unit must prepare a notification stating that an assessment monitoring program has been established. The owner or operator has completed the notification when the notification is placed in the facility's operating record as required by § 257.105(h)(5).

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

§ 257.95 Assessment monitoring program.

(a) Assessment monitoring is required whenever a statistically significant increase over background levels has been detected for one or more of the constituents listed in appendix III to this part.

(b) Within 90 days of triggering an assessment monitoring program, and annually thereafter, the owner or operator of the CCR unit must sample and analyze the groundwater for all constituents listed in appendix IV to this part. The number of samples collected and analyzed for each well during each sampling event must be consistent with § 257.93(e), and must account for any unique characteristics of the site, but must be at least one sample from each well.

(c) The owner or operator of a CCR unit may demonstrate the need for an alternative monitoring frequency for repeated sampling and analysis for constituents listed in appendix IV to this part during the active life and the post-closure care period based on the availability of groundwater. If there is not adequate groundwater flow to sample wells semiannually, the alternative frequency shall be no less than annual. The need to vary monitoring frequency must be evaluated on a site-specific basis. The demonstration must be supported by, at a minimum, the information specified in paragraphs (c)(1) and (2) of this section.

(1) Information documenting that the need for less frequent sampling. The alternative frequency must be based on consideration of the following factors:

(i) Lithology of the aquifer and unsaturated zone;

(ii) Hydraulic conductivity of the aquifer and unsaturated zone; and

(iii) Groundwater flow rates.

(2) Information documenting that the alternative frequency will be no less effective in ensuring that any leakage from the CCR unit will be discovered within a timeframe that will not materially delay the initiation of any necessary remediation measures.

(3) The owner or operator must obtain a certification from a qualified professional engineer stating that the demonstration for an alternative groundwater sampling and analysis frequency meets the requirements of this section. The owner or operator must include the demonstration providing the basis for the alternative monitoring frequency and the certification by a qualified professional engineer in the annual groundwater monitoring and corrective action report required by § 257.90(e).

(d) After obtaining the results from the initial and subsequent sampling events required in paragraph (b) of this section, the owner or operator must:

(1) Within 90 days of obtaining the results, and on at least a semiannual basis thereafter, resample all wells that were installed pursuant to the requirements of § 257.91, conduct analyses for all parameters in appendix III to this part and for those constituents in appendix IV to this part that are detected in response to paragraph (b) of this section, and record their concentrations in the facility operating record. The number of samples collected and analyzed for each background well and downgradient well during subsequent semiannual sampling events must be consistent with § 257.93(e), and must account for any unique characteristics of the site, but must be at least one sample from each background and downgradient well;

(2) Establish groundwater protection standards for all constituents detected pursuant to paragraph (b) or (d) of this section. The groundwater protection standards must be established in accordance with paragraph (h) of this section; and

(3) Include the recorded concentrations required by paragraph (d)(1) of this section, identify the background concentrations established under § 257.94(b), and identify the groundwater protection standards established under paragraph (d)(2) of this section in the annual groundwater monitoring and corrective action report required by § 257.90(e).

(e) If the concentrations of all constituents listed in appendices III and IV to this part are shown to be at or below background values, using the statistical procedures in § 257.93(g), for two consecutive sampling events, the owner or operator may return to detection monitoring of the CCR unit. The owner or operator must prepare a notification stating that detection monitoring is resuming for the CCR unit. The owner or operator has completed the notification when the notification is placed in the facility's operating record as required by § 257.105(h)(7).

(f) If the concentrations of any constituent in appendices III and IV to this part are above background values, but all concentrations are below the groundwater protection standard

established under paragraph (h) of this section, using the statistical procedures in § 257.93(g), the owner or operator must continue assessment monitoring in accordance with this section.

(g) If one or more constituents in appendix IV to this part are detected at statistically significant levels above the groundwater protection standard established under paragraph (h) of this section in any sampling event, the owner or operator must prepare a notification identifying the constituents in appendix IV to this part that have exceeded the groundwater protection standard. The owner or operator has completed the notification when the notification is placed in the facility's operating record as required by § 257.105(h)(8). The owner or operator of the CCR unit also must:

(1) Characterize the nature and extent of the release and any relevant site conditions that may affect the remedy ultimately selected. The characterization must be sufficient to support a complete and accurate assessment of the corrective measures necessary to effectively clean up all releases from the CCR unit pursuant to § 257.96. Characterization of the release includes the following minimum measures:

(i) Install additional monitoring wells necessary to define the contaminant plume(s);

(ii) Collect data on the nature and estimated quantity of material released including specific information on the constituents listed in appendix IV of this part and the levels at which they are present in the material released;

(iii) Install at least one additional monitoring well at the facility boundary in the direction of contaminant migration and sample this well in accordance with paragraph (d)(1) of this section; and

(iv) Sample all wells in accordance with paragraph (d)(1) of this section to characterize the nature and extent of the release.

(2) Notify all persons who own the land or reside on the land that directly overlies any part of the plume of contamination if contaminants have migrated off-site if indicated by sampling of wells in accordance with paragraph (g)(1) of this section. The owner or operator has completed the notifications when they are placed in the facility's operating record as required by § 257.105(h)(8).

(3) Within 90 days of finding that any of the constituents listed in appendix IV to this part have been detected at a statistically significant level exceeding the groundwater protection standards the owner or operator must either:

(i) Initiate an assessment of corrective measures as required by § 257.96; or

(ii) Demonstrate that a source other than the CCR unit caused the contamination, or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality. Any such demonstration must be supported by a report that includes the factual or evidentiary basis for any conclusions and must be certified to be accurate by a qualified professional engineer. If a successful demonstration is made, the owner or operator must continue monitoring in accordance with the assessment monitoring program pursuant to this section, and may return to detection monitoring if the constituents in appendices III and IV to this part are at or below background as specified in paragraph (e) of this section. The owner or operator must also include the demonstration in the annual groundwater monitoring and corrective action report required by § 257.90(e), in addition to the certification by a qualified professional engineer.

(4) If a successful demonstration has not been made at the end of the 90 day period provided by paragraph (g)(3)(ii) of this section, the owner or operator of the CCR unit must initiate the assessment of corrective measures requirements under § 257.96.

(5) If an assessment of corrective measures is required under § 257.96 by either paragraph (g)(3)(i) or (g)(4) of this section, and if the CCR unit is an existing unlined CCR surface impoundment as determined by § 257.71(a), then the CCR unit is subject to the closure requirements under § 257.101(a) to retrofit or close. In addition, the owner or operator must prepare a notification stating that an assessment of corrective measures has been initiated.

(h) The owner or operator of the CCR unit must establish a groundwater protection standard for each constituent in appendix IV to this part detected in the groundwater. The groundwater protection standard shall be:

(1) For constituents for which a maximum contaminant level (MCL) has been established under §§ 141.62 and 141.66 of this title, the MCL for that constituent;

(2) For constituents for which an MCL has not been established, the background concentration for the constituent established from wells in accordance with § 257.91; or

(3) For constituents for which the background level is higher than the MCL identified under paragraph (h)(1) of this section, the background concentration.

(i) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

§ 257.96 Assessment of corrective measures.

(a) Within 90 days of finding that any constituent listed in appendix IV to this part has been detected at a statistically significant level exceeding the groundwater protection standard defined under § 257.95(h), or immediately upon detection of a release from a CCR unit, the owner or operator must initiate an assessment of corrective measures to prevent further releases, to remediate any releases and to restore affected area to original conditions. The assessment of corrective measures must be completed within 90 days, unless the owner or operator demonstrates the need for additional time to complete the assessment of corrective measures due to site-specific conditions or circumstances. The owner or operator must obtain a certification from a qualified professional engineer attesting that the demonstration is accurate. The 90-day deadline to complete the assessment of corrective measures may be extended for no longer than 60 days. The owner or operator must also include the demonstration in the annual groundwater monitoring and corrective action report required by § 257.90(e), in addition to the certification by a qualified professional engineer.

(b) The owner or operator of the CCR unit must continue to monitor groundwater in accordance with the assessment monitoring program as specified in § 257.95.

(c) The assessment under paragraph (a) of this section must include an analysis of the effectiveness of potential corrective measures in meeting all of the requirements and objectives of the remedy as described under § 257.97 addressing at least the following:

(1) The performance, reliability, ease of implementation, and potential impacts of appropriate potential remedies, including safety impacts, cross-media impacts, and control of exposure to any residual contamination;

(2) The time required to begin and complete the remedy;

(3) The institutional requirements, such as state or local permit requirements or other environmental or public health requirements that may substantially affect implementation of the remedy(s).

(d) The owner or operator must place the completed assessment of corrective measures in the facility's operating record. The assessment has been completed when it is placed in the facility's operating record as required by § 257.105(h)(10).

(e) The owner or operator must discuss the results of the corrective measures assessment at least 30 days prior to the selection of remedy, in a public meeting with interested and affected parties.

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

§ 257.97 Selection of remedy.

(a) Based on the results of the corrective measures assessment conducted under § 257.96, the owner or operator must, as soon as feasible, select a remedy that, at a minimum, meets the standards listed in paragraph (b) of this section. This requirement applies to, not in place of, any applicable standards under the Occupational Safety and Health Act. The owner or operator must prepare a semiannual report describing the progress in selecting and designing the remedy. Upon selection of a remedy, the owner or operator must prepare a final report describing the selected remedy and how it meets the standards specified in paragraph (b) of this section. The owner or operator must obtain a certification from a qualified professional engineer that the remedy selected meets the requirements of this section. The report has been completed when it is placed in the operating record as required by § 257.105(h)(12).

(b) Remedies must:

(1) Be protective of human health and the environment;

(2) Attain the groundwater protection standard as specified pursuant to § 257.95(h);

(3) Control the source(s) of releases so as to reduce or eliminate, to the maximum extent feasible, further releases of constituents in appendix IV to this part into the environment;

(4) Remove from the environment as much of the contaminated material that was released from the CCR unit as is feasible, taking into account factors such as avoiding inappropriate disturbance of sensitive ecosystems;

(5) Comply with standards for management of wastes as specified in § 257.98(d).

(c) In selecting a remedy that meets the standards of paragraph (b) of this section, the owner or operator of the CCR unit shall consider the following evaluation factors:

(1) The long- and short-term effectiveness and protectiveness of the potential remedy(s), along with the degree of certainty that the remedy will prove successful based on consideration of the following:

(i) Magnitude of reduction of existing risks;

(ii) Magnitude of residual risks in terms of likelihood of further releases due to CCR remaining following implementation of a remedy;

(iii) The type and degree of long-term management required, including monitoring, operation, and maintenance;

(iv) Short-term risks that might be posed to the community or the environment during implementation of such a remedy, including potential threats to human health and the environment associated with excavation, transportation, and re-disposal of contaminant;

(v) Time until full protection is achieved;

(vi) Potential for exposure of humans and environmental receptors to remaining wastes, considering the potential threat to human health and the environment associated with excavation, transportation, re-disposal, or containment;

(vii) Long-term reliability of the engineering and institutional controls; and

(viii) Potential need for replacement of the remedy.

(2) The effectiveness of the remedy in controlling the source to reduce further releases based on consideration of the following factors:

(i) The extent to which containment practices will reduce further releases; and

(ii) The extent to which treatment technologies may be used.

(3) The ease or difficulty of implementing a potential remedy(s) based on consideration of the following types of factors:

(i) Degree of difficulty associated with constructing the technology;

(ii) Expected operational reliability of the technologies;

(iii) Need to coordinate with and obtain necessary approvals and permits from other agencies;

(iv) Availability of necessary equipment and specialists; and

(v) Available capacity and location of needed treatment, storage, and disposal services.

(4) The degree to which community concerns are addressed by a potential remedy(s).

(d) The owner or operator must specify as part of the selected remedy a schedule(s) for implementing and completing remedial activities. Such a schedule must require the completion of remedial activities within a reasonable period of time taking into consideration the factors set forth in paragraphs (d)(1) through (6) of this section. The owner or operator of the CCR unit must consider the following factors in determining the schedule of remedial activities:

(1) Extent and nature of contamination, as determined by the characterization required under § 257.95(g);

(2) Reasonable probabilities of remedial technologies in achieving compliance with the groundwater protection standards established under § 257.95(h) and other objectives of the remedy;

(3) Availability of treatment or disposal capacity for CCR managed during implementation of the remedy;

(4) Potential risks to human health and the environment from exposure to contamination prior to completion of the remedy;

(5) Resource value of the aquifer including:

(i) Current and future uses;

(ii) Proximity and withdrawal rate of users;

(iii) Groundwater quantity and quality;

(iv) The potential damage to wildlife, crops, vegetation, and physical structures caused by exposure to CCR constituents;

(v) The hydrogeologic characteristic of the facility and surrounding land; and

(vi) The availability of alternative water supplies; and

(6) Other relevant factors.

(e) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the Internet requirements specified in § 257.107(h).

§ 257.98 Implementation of the corrective action program.

(a) Within 90 days of selecting a remedy under § 257.97, the owner or operator must initiate remedial activities. Based on the schedule established under § 257.97(d) for implementation and completion of remedial activities the owner or operator must:

(1) Establish and implement a corrective action groundwater monitoring program that:

(i) At a minimum, meets the requirements of an assessment monitoring program under § 257.95;

(ii) Documents the effectiveness of the corrective action remedy; and

(iii) Demonstrates compliance with the groundwater protection standard pursuant to paragraph (c) of this section.

(2) Implement the corrective action remedy selected under § 257.97; and

(3) Take any interim measures necessary to reduce the contaminants leaching from the CCR unit, and/or potential exposures to human or ecological receptors. Interim measures must, to the greatest extent feasible, be consistent with the objectives of and contribute to the performance of any remedy that may be required pursuant to § 257.97. The following factors must be considered by an owner or operator in determining whether interim measures are necessary:

(i) Time required to develop and implement a final remedy;

(ii) Actual or potential exposure of nearby populations or environmental receptors to any of the constituents listed in appendix IV of this part;

(iii) Actual or potential contamination of drinking water supplies or sensitive ecosystems;

(iv) Further degradation of the groundwater that may occur if remedial action is not initiated expeditiously;

(v) Weather conditions that may cause any of the constituents listed in appendix IV to this part to migrate or be released;

(vi) Potential for exposure to any of the constituents listed in appendix IV to this part as a result of an accident or failure of a container or handling system; and

(vii) Other situations that may pose threats to human health and the environment.

(b) If an owner or operator of the CCR unit, determines, at any time, that compliance with the requirements of § 257.97(b) is not being achieved through the remedy selected, the owner or operator must implement other methods or techniques that could feasibly achieve compliance with the requirements.

(c) Remedies selected pursuant to § 257.97 shall be considered complete when:

(1) The owner or operator of the CCR unit demonstrates compliance with the groundwater protection standards established under § 257.95(h) has been achieved at all points within the plume of contamination that lie beyond the groundwater monitoring well system established under § 257.91.

(2) Compliance with the groundwater protection standards established under § 257.95(h) has been achieved by demonstrating that concentrations of constituents listed in appendix IV to this part have not exceeded the groundwater protection standard(s) for a period of three consecutive years using the statistical procedures and performance standards in § 257.93(f) and (g).

(3) All actions required to complete the remedy have been satisfied.

(d) All CCR that are managed pursuant to a remedy required under § 257.97, or an interim measure required under paragraph (a)(3) of this section, shall be managed in a manner that complies with all applicable RCRA requirements.

(e) Upon completion of the remedy, the owner or operator must prepare a notification stating that the remedy has been completed. The owner or operator must obtain a certification from a qualified professional engineer attesting that the remedy has been completed in compliance with the requirements of paragraph (c) of this section. The report has been completed when it is placed in the operating record as required by § 257.105(h)(13).

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h).

Closure and Post-Closure Care

§ 257.100 Inactive CCR surface impoundments.

(a) Except as provided by paragraph (b) of this section, inactive CCR surface impoundments are subject to all of the requirements of this subpart applicable to existing CCR surface impoundments.

(b) An owner or operator of an inactive CCR surface impoundment that completes closure of such CCR unit, and meets all of the requirements of either paragraphs (b)(1) through (4) of this section or paragraph (b)(5) of this section no later than April 17, 2018, is exempt from all other requirements of this subpart.

(1) *Closure by leaving CCR in place.* If the owner or operator of the inactive CCR surface impoundment elects to close the CCR surface impoundment by leaving CCR in place, the owner or operator must ensure that, at a minimum, the CCR unit is closed in a manner that will:

(i) Control, minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere;

(ii) Preclude the probability of future impoundment of water, sediment, or slurry;

(iii) Include measures that provide for major slope stability to prevent the sloughing or movement of the final cover system; and

(iv) Minimize the need for further maintenance of the CCR unit.

(2) The owner or operator of the inactive CCR surface impoundment must meet the requirements of paragraphs (b)(2)(i) and (ii) of this section prior to installing the final cover system required under paragraph (b)(3) of this section.

(i) Free liquids must be eliminated by removing liquid wastes or solidifying the remaining wastes and waste residues.

(ii) Remaining wastes must be stabilized sufficient to support the final cover system.

(3) The owner or operator must install a final cover system that is designed to minimize infiltration and erosion, and at a minimum, meets the requirements of paragraph (b)(3)(i) of this section, or the requirements of an alternative final cover system specified in paragraph (b)(3)(ii) of this section.

(i) The final cover system must be designed and constructed to meet the criteria specified in paragraphs (b)(3)(i)(A) through (D) of this section.

(A) The permeability of the final cover system must be less than or equal to the permeability of any bottom liner system or natural subsoils present, or a permeability no greater than 1×10^{-5} centimeters/second, whichever is less.

(B) The infiltration of liquids through the CCR unit must be minimized by the use of an infiltration layer that contains a minimum of 18 inches of earthen material.

(C) The erosion of the final cover system must be minimized by the use of an erosion layer that contains a minimum of six inches of earthen material that is capable of sustaining native plant growth.

(D) The disruption of the integrity of the final cover system must be minimized through a design that accommodates settling and subsidence.

(ii) The owner or operator may select an alternative final cover system design, provided the alternative final cover system is designed and constructed to meet the criteria in paragraphs (b)(3)(ii)(A) through (C) of this section.

(A) The design of the final cover system must include an infiltration layer that achieves an equivalent reduction in infiltration as the infiltration layer specified in paragraphs (b)(3)(i)(A) and (B) of this section.

(B) The design of the final cover system must include an erosion layer that provides equivalent protection from wind or water erosion as the erosion layer specified in paragraph (b)(3)(i)(C) of this section.

(C) The disruption of the integrity of the final cover system must be minimized through a design that accommodates settling and subsidence.

(4) The owner or operator of the CCR surface impoundment must obtain a written certification from a qualified professional engineer stating that the design of the final cover system meets either the requirements of paragraphs (b)(3)(i) or (ii) of this section.

(5) *Closure through removal of CCR.* The owner or operator may alternatively elect to close an inactive CCR surface impoundment by removing and decontaminating all areas affected by releases from the CCR surface impoundment. CCR removal and decontamination of the CCR surface impoundment are complete when all CCR in the inactive CCR surface impoundment is removed, including the bottom liner of the CCR unit.

(6) The owner or operator of the CCR surface impoundment must obtain a written certification from a qualified professional engineer that closure of the CCR surface impoundment under either paragraphs (b)(1) through (4) or (b)(5) of this section is technically feasible within the timeframe in paragraph (b) of this section.

(7) If the owner or operator of the CCR surface impoundment fails to complete closure of the inactive CCR surface impoundment within the timeframe in paragraph (b) of this section, the CCR unit must comply with all of the requirements applicable to existing CCR surface impoundments under this subpart.

(c) *Required notices and progress reports.* An owner or operator of an inactive CCR surface impoundment that closes in accordance with paragraph (b) of this section must complete the notices and progress reports specified in paragraphs (c)(1) through (3) of this section.

(1) No later than December 17, 2015, the owner or operator must prepare and place in the facility's operating record a notification of intent to initiate closure of the CCR surface impoundment. The notification must state that the CCR surface impoundment is an inactive CCR surface impoundment closing under the requirements of paragraph (b) of this section. The notification must also include a narrative description of how the CCR surface impoundment will be closed, a schedule for completing closure activities, and the required certifications under paragraphs (b)(4) and (6) of this section, if applicable.

(2) The owner or operator must prepare periodic progress reports summarizing the progress of closure implementation, including a description of the actions completed to date, any problems encountered and a description of the actions taken to resolve the problems, and projected closure activities for the upcoming year. The annual progress reports must be completed according to the following schedule:

(i) The first annual progress report must be prepared no later than 13 months after completing the notification of intent to initiate closure required by paragraph (c)(1) of this section.

(ii) The second annual progress report must be prepared no later than 12 months after completing the first progress report required by paragraph (c)(2)(i) of this section.

(iii) The owner or operator has completed the progress reports specified in paragraph (c)(2) of this section when the reports are placed in the facility's operating record as required by § 257.105(i)(2).

(3) The owner or operator must prepare and place in the facility's operating record a notification of completion of closure of the CCR surface impoundment. The notification must be submitted within 60 days of completing closure of the CCR surface impoundment and must include a written certification from a qualified professional engineer stating that the CCR surface impoundment was closed in accordance with the requirements of either paragraph (b)(1) through (4) or (b)(5) of this section.

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(i), the notification requirements specified in § 257.106(i), and the internet requirements specified in § 257.107(i).

§ 257.101 Closure or retrofit of CCR units.

(a) The owner or operator of an existing unlined CCR surface impoundment, as determined under § 257.71(a), is subject to the requirements of paragraph (a)(1) of this section.

(1) Except as provided by paragraph (a)(3) of this section, if at any time after October 19, 2015 an owner or operator of an existing unlined CCR surface impoundment determines in any sampling event that the concentrations of one or more constituents listed in appendix IV to this part are detected at statistically significant levels above the groundwater protection standard established under § 257.95(h) for such CCR unit, within six months of making such determination, the owner or operator of the existing unlined CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR surface impoundment and either retrofit or close the CCR unit in accordance with the requirements of § 257.102.

(2) An owner or operator of an existing unlined CCR surface impoundment that closes in accordance with paragraph (a)(1) of this section must include a statement in the notification required under § 257.102(g) or (k)(5) that the CCR surface impoundment is closing or retrofitting under the requirements of paragraph (a)(1) of this section.

(3) The timeframe specified in paragraph (a)(1) of this section does not apply if the owner or operator complies with the alternative closure procedures specified in § 257.103.

(4) At any time after the initiation of closure under paragraph (a)(1) of this section, the owner or operator may cease closure activities and initiate a retrofit of the CCR unit in accordance with the requirements of § 257.102(k).

(b) The owner or operator of an existing CCR surface impoundment is subject to the requirements of paragraph (b)(1) of this section.

(1) Except as provided by paragraph (b)(4) of this section, within six months of determining that an existing CCR surface impoundment has not demonstrated compliance with any location standard specified in §§ 257.60(a), 257.61(a), 257.62(a), 257.63(a), and 257.64(a), the owner or operator of the CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR unit and close the CCR unit in accordance with the requirements of § 257.102.

(2) Within six months of either failing to complete the initial or any subsequent periodic safety factor assessment required by § 257.73(e) by the deadlines specified in § 257.73(f)(1) through (3) or failing to document that the calculated factors of safety for the existing CCR surface impoundment achieve the minimum safety factors specified in § 257.73(e)(1)(i) through (iv), the owner or operator of the CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR unit and close the CCR unit in accordance with the requirements of § 257.102.

(3) An owner or operator of an existing CCR surface impoundment that closes in accordance with paragraphs (b)(1) or (2) of this section must include a statement in the notification required under § 257.102(g) that the CCR surface impoundment is closing under the requirements of paragraphs (b)(1) or (2) of this section.

(4) The timeframe specified in paragraph (b)(1) of this section does not apply if the owner or operator complies with the alternative closure procedures specified in § 257.103.

(c) The owner or operator of a new CCR surface impoundment is subject to the requirements of paragraph (c)(1) of this section.

(1) Within six months of either failing to complete the initial or any subsequent periodic safety factor assessment required by § 257.74(e) by the deadlines specified in § 257.74(f)(1) through (3) or failing to document that the calculated factors of safety for the new CCR surface impoundment achieve the minimum safety factors specified in § 257.74(e)(1)(i) through (v), the owner or operator of the CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR unit and close the CCR unit in accordance with the requirements of § 257.102.

(2) An owner or operator of an new CCR surface impoundment that closes in accordance with paragraph (c)(1) of this section must include a statement in the notification required under § 257.102(g) that the CCR surface impoundment is closing under the requirements of paragraph (c)(1) of this section.

(d) The owner or operator of an existing CCR landfill is subject to the requirements of paragraph (d)(1) of this section.

(1) Except as provided by paragraph (d)(3) of this section, within six months of determining that an existing CCR landfill has not demonstrated compliance with the location restriction for unstable areas specified in § 257.64(a), the owner or operator of the CCR unit must cease placing CCR and non-CCR waste streams into such CCR landfill and close the CCR unit in accordance with the requirements of § 257.102.

(2) An owner or operator of an existing CCR landfill that closes in accordance with paragraph (d)(1) of this section must include a statement in the notification required under § 257.102(g) that the CCR landfill is closing under the requirements of paragraph (d)(1) of this section.

(3) The timeframe specified in paragraph (d)(1) of this section does not apply if the owner or operator complies with the alternative closure procedures specified in § 257.103.

§ 257.102 Criteria for conducting the closure or retrofit of CCR units.

(a) Closure of a CCR landfill, CCR surface impoundment, or any lateral expansion of a CCR unit must be completed either by leaving the CCR in place and installing a final cover system or through removal of the CCR and decontamination of the CCR unit, as described in paragraphs (b) through (j) of this section. Retrofit of a CCR surface impoundment must be completed in accordance with the requirements in paragraph (k) of this section.

(b) *Written closure plan*—(1) *Content of the plan.* The owner or operator of a CCR unit must prepare a written closure plan that describes the steps necessary to close the CCR unit at any point during the active life of the CCR unit consistent with recognized and generally accepted good engineering practices. The written closure plan must include, at a minimum, the information specified in paragraphs (b)(1)(i) through (vi) of this section.

(i) A narrative description of how the CCR unit will be closed in accordance with this section.

(ii) If closure of the CCR unit will be accomplished through removal of CCR from the CCR unit, a description of the procedures to remove the CCR and decontaminate the CCR unit in accordance with paragraph (c) of this section.

(iii) If closure of the CCR unit will be accomplished by leaving CCR in place, a description of the final cover system, designed in accordance with paragraph (d) of this section, and the methods and procedures to be used to install the final cover. The closure plan must also discuss how the final cover system will achieve the performance standards specified in paragraph (d) of this section.

(iv) An estimate of the maximum inventory of CCR ever on-site over the active life of the CCR unit.

(v) An estimate of the largest area of the CCR unit ever requiring a final cover as required by paragraph (d) of this section at any time during the CCR unit's active life.

(vi) A schedule for completing all activities necessary to satisfy the closure criteria in this section, including an estimate of the year in which all closure activities for the CCR unit will be completed. The schedule should provide sufficient information to describe the sequential steps that will be taken to close the CCR unit, including identification of major milestones such as coordinating with and obtaining necessary approvals and permits from other agencies, the dewatering and stabilization phases of CCR surface impoundment closure, or installation of the final cover system, and the estimated timeframes to complete each step or phase of CCR unit closure. When preparing the written closure plan, if the owner or operator of a CCR unit estimates that the time required to complete closure will exceed the timeframes specified in paragraph (f)(1) of this section, the written closure plan must include the site-specific information, factors and considerations that would support any time extension sought under paragraph (f)(2) of this section.

(2) *Timeframes for preparing the initial written closure plan*—(i) *Existing CCR landfills and existing CCR surface impoundments.* No later than October 17, 2016, the owner or operator of the CCR unit must prepare an initial written closure plan consistent with the requirements specified in paragraph (b)(1) of this section.

(ii) *New CCR landfills and new CCR surface impoundments, and any lateral expansion of a CCR unit.* No later than the date of the initial receipt of CCR in the CCR unit, the owner or operator must prepare an initial written closure plan consistent with the requirements specified in paragraph (b)(1) of this section.

(iii) The owner or operator has completed the written closure plan when the plan, including the certification required by paragraph (b)(4) of this section, has been placed in the facility's operating record as required by § 257.105(i)(4).

(3) *Amendment of a written closure plan.* (i) The owner or operator may amend the initial or any subsequent written closure plan developed pursuant to paragraph (b)(1) of this section at any time.

(ii) The owner or operator must amend the written closure plan whenever:

(A) There is a change in the operation of the CCR unit that would substantially affect the written closure plan in effect; or

(B) Before or after closure activities have commenced, unanticipated events necessitate a revision of the written closure plan.

(iii) The owner or operator must amend the closure plan at least 60 days prior to a planned change in the operation of the facility or CCR unit, or no later than 60 days after an unanticipated event requires the need to revise an existing written closure plan. If a written closure plan is revised after closure activities have commenced for a CCR unit, the owner or operator must amend the current closure plan no later than 30 days following the triggering event.

(4) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer that the initial and any amendment of

the written closure plan meets the requirements of this section.

(c) *Closure by removal of CCR.* An owner or operator may elect to close a CCR unit by removing and decontaminating all areas affected by releases from the CCR unit. CCR removal and decontamination of the CCR unit are complete when constituent concentrations throughout the CCR unit and any areas affected by releases from the CCR unit have been removed and groundwater monitoring concentrations do not exceed the groundwater protection standard established pursuant to § 257.95(h) for constituents listed in appendix IV to this part.

(d) *Closure performance standard when leaving CCR in place*—(1) The owner or operator of a CCR unit must ensure that, at a minimum, the CCR unit is closed in a manner that will:

(i) Control, minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters or to the atmosphere;

(ii) Preclude the probability of future impoundment of water, sediment, or slurry;

(iii) Include measures that provide for major slope stability to prevent the sloughing or movement of the final cover system during the closure and post-closure care period;

(iv) Minimize the need for further maintenance of the CCR unit; and

(v) Be completed in the shortest amount of time consistent with recognized and generally accepted good engineering practices.

(2) *Drainage and stabilization of CCR surface impoundments.* The owner or operator of a CCR surface impoundment or any lateral expansion of a CCR surface impoundment must meet the requirements of paragraphs (d)(2)(i) and (ii) of this section prior to installing the final cover system required under paragraph (d)(3) of this section.

(i) Free liquids must be eliminated by removing liquid wastes or solidifying the remaining wastes and waste residues.

(ii) Remaining wastes must be stabilized sufficient to support the final cover system.

(3) *Final cover system.* If a CCR unit is closed by leaving CCR in place, the owner or operator must install a final cover system that is designed to minimize infiltration and erosion, and at a minimum, meets the requirements of paragraph (d)(3)(i) of this section, or the requirements of the alternative final cover system specified in paragraph (d)(3)(ii) of this section.

(i) The final cover system must be designed and constructed to meet the criteria in paragraphs (d)(3)(i)(A) through (D) of this section. The design of the final cover system must be included in the written closure plan required by paragraph (b) of this section.

(A) The permeability of the final cover system must be less than or equal to the permeability of any bottom liner system or natural subsoils present, or a permeability no greater than 1×10^{-5} cm/sec, whichever is less.

(B) The infiltration of liquids through the closed CCR unit must be minimized by the use of an infiltration layer that contains a minimum of 18 inches of earthen material.

(C) The erosion of the final cover system must be minimized by the use of an erosion layer that contains a minimum of six inches of earthen material that is capable of sustaining native plant growth.

(D) The disruption of the integrity of the final cover system must be minimized through a design that accommodates settling and subsidence.

(ii) The owner or operator may select an alternative final cover system design, provided the alternative final cover system is designed and constructed to meet the criteria in paragraphs (f)(3)(ii)(A) through (D) of this section. The design of the final cover system must be included in the written closure plan required by paragraph (b) of this section.

(A) The design of the final cover system must include an infiltration layer that achieves an equivalent reduction in infiltration as the infiltration layer specified in paragraphs (d)(3)(i)(A) and (B) of this section.

(B) The design of the final cover system must include an erosion layer that provides equivalent protection from wind or water erosion as the erosion layer specified in paragraph (d)(3)(i)(C) of this section.

(C) The disruption of the integrity of the final cover system must be minimized through a design that accommodates settling and subsidence.

(iii) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer that the design of the final cover system meets the requirements of this section.

(e) *Initiation of closure activities.* Except as provided for in paragraph (e)(4) of this section and § 257.103, the owner or operator of a CCR unit must commence closure of the CCR unit no later than the applicable timeframes specified in either paragraph (e)(1) or (2) of this section.

(1) The owner or operator must commence closure of the CCR unit no later than 30 days after the date on which the CCR unit either:

(i) Receives the known final receipt of waste, either CCR or any non-CCR waste stream; or

(ii) Removes the known final volume of CCR from the CCR unit for the purpose of beneficial use of CCR.

(2)(i) Except as provided by paragraph (e)(2)(ii) of this section, the owner or operator must commence closure of a CCR unit that has not received CCR or any non-CCR waste stream or is no longer removing CCR for the purpose of beneficial use within two years of the last receipt of waste or within two years of the last removal of CCR material for the purpose of beneficial use.

(ii) Notwithstanding paragraph (e)(2)(i) of this section, the owner or operator of the CCR unit may secure an additional two years to initiate closure of the idle unit provided the owner or operator provides written documentation that the CCR unit will continue to accept wastes or will start removing CCR for the purpose of beneficial use. The documentation must be supported by, at a minimum, the information specified in paragraphs (e)(2)(ii)(A) and (B) of this section. The owner or operator may obtain two-year extensions provided the owner or operator continues to be able to demonstrate that there is reasonable likelihood that the CCR unit will accept wastes in the foreseeable future or will remove CCR from the unit for the purpose of beneficial use. The owner or operator must place each completed demonstration, if more than one time extension is sought, in the facility's operating record as required by § 257.105(i)(5) prior to the end of any two-year period.

(A) Information documenting that the CCR unit has remaining storage or disposal capacity or that the CCR unit can have CCR removed for the purpose of beneficial use; and

(B) Information demonstrating that that there is a reasonable likelihood that the CCR unit will resume receiving CCR or non-CCR waste streams in the foreseeable future or that CCR can be removed for the purpose of beneficial use. The narrative must include a best estimate as to when the CCR unit will resume receiving CCR or non-CCR waste streams. The situations listed in paragraphs (e)(2)(ii)(B)(*1*) through (*4*) of this section are examples of situations that would support a determination that the CCR unit will resume receiving CCR or non-CCR waste streams in the foreseeable future.

(*1*) Normal plant operations include periods during which the CCR unit does not receive CCR or non-CCR waste

streams, such as the alternating use of two or more CCR units whereby at any point in time one CCR unit is receiving CCR while CCR is being removed from a second CCR unit after its dewatering.

(*2*) The CCR unit is dedicated to a coal-fired boiler unit that is temporarily idled (*e.g.,* CCR is not being generated) and there is a reasonable likelihood that the coal-fired boiler will resume operations in the future.

(*3*) The CCR unit is dedicated to an operating coal-fired boiler (*i.e.,* CCR is being generated); however, no CCR are being placed in the CCR unit because the CCR are being entirely diverted to beneficial uses, but there is a reasonable likelihood that the CCR unit will again be used in the foreseeable future.

(*4*) The CCR unit currently receives only non-CCR waste streams and those non-CCR waste streams are not generated for an extended period of time, but there is a reasonable likelihood that the CCR unit will again receive non-CCR waste streams in the future.

(iii) In order to obtain additional time extension(s) to initiate closure of a CCR unit beyond the two years provided by paragraph (e)(2)(i) of this section, the owner or operator of the CCR unit must include with the demonstration required by paragraph (e)(2)(ii) of this section the following statement signed by the owner or operator or an authorized representative:

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this demonstration and all attached documents, and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

(3) For purposes of this subpart, closure of the CCR unit has commenced if the owner or operator has ceased placing waste and completes any of the following actions or activities:

(i) Taken any steps necessary to implement the written closure plan required by paragraph (b) of this section;

(ii) Submitted a completed application for any required state or agency permit or permit modification; or

(iii) Taken any steps necessary to comply with any state or other agency standards that are a prerequisite, or are otherwise applicable, to initiating or completing the closure of a CCR unit.

(4) The timeframes specified in paragraphs (e)(1) and (2) of this section do not apply to any of the following owners or operators:

(i) An owner or operator of an inactive CCR surface impoundment closing the CCR unit as required by § 257.100(b);

(ii) An owner or operator of an existing unlined CCR surface impoundment closing the CCR unit as required by § 257.101(a);

(iii) An owner or operator of an existing CCR surface impoundment closing the CCR unit as required by § 257.101(b);

(iv) An owner or operator of a new CCR surface impoundment closing the CCR unit as required by § 257.101(c); or

(v) An owner or operator of an existing CCR landfill closing the CCR unit as required by § 257.101(d).

(f) *Completion of closure activities.* (1) Except as provided for in paragraph (f)(2) of this section, the owner or operator must complete closure of the CCR unit:

(i) For existing and new CCR landfills and any lateral expansion of a CCR landfill, within six months of commencing closure activities.

(ii) For existing and new CCR surface impoundments and any lateral expansion of a CCR surface impoundment, within five years of commencing closure activities.

(2)(i) *Extensions of closure timeframes.* The timeframes for completing closure of a CCR unit specified under paragraphs (f)(1) of this section may be extended if the owner or operator can demonstrate that it was not feasible to complete closure of the CCR unit within the required timeframes due to factors beyond the facility's control. If the owner or operator is seeking a time extension beyond the time specified in the written closure plan as required by paragraph (b)(1) of this section, the demonstration must include a narrative discussion providing the basis for additional time beyond that specified in the closure plan. The owner or operator must place each completed demonstration, if more than one time extension is sought, in the facility's operating record as required by § 257.105(i)(6) prior to the end of any two-year period. Factors that may support such a demonstration include:

(A) Complications stemming from the climate and weather, such as unusual amounts of precipitation or a significantly shortened construction season;

(B) Time required to dewater a surface impoundment due to the volume of CCR contained in the CCR unit or the characteristics of the CCR in the unit;

(C) The geology and terrain surrounding the CCR unit will affect the amount of material needed to close the CCR unit; or

(D) Time required or delays caused by the need to coordinate with and obtain necessary approvals and permits from a state or other agency.

(ii) *Maximum time extensions.* (A) CCR surface impoundments of 40 acres or smaller may extend the time to complete closure by no longer than two years.

(B) CCR surface impoundments larger than 40 acres may extend the timeframe to complete closure of the CCR unit multiple times, in two-year increments. For each two-year extension sought, the owner or operator must substantiate the factual circumstances demonstrating the need for the extension. No more than a total of five two-year extensions may be obtained for any CCR surface impoundment.

(C) CCR landfills may extend the timeframe to complete closure of the CCR unit multiple times, in one-year increments. For each one-year extension sought, the owner or operator must substantiate the factual circumstances demonstrating the need for the extension. No more than a total of two one-year extensions may be obtained for any CCR landfill.

(iii) In order to obtain additional time extension(s) to complete closure of a CCR unit beyond the times provided by paragraph (f)(1) of this section, the owner or operator of the CCR unit must include with the demonstration required by paragraph (f)(2)(i) of this section the following statement signed by the owner or operator or an authorized representative:

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this demonstration and all attached documents, and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

(3) Upon completion, the owner or operator of the CCR unit must obtain a certification from a qualified professional engineer verifying that closure has been completed in accordance with the closure plan specified in paragraph (b) of this section and the requirements of this section.

(g) No later than the date the owner or operator initiates closure of a CCR unit, the owner or operator must prepare a notification of intent to close a CCR unit. The notification must include the certification by a qualified professional engineer for the design of the final cover system as required by § 257.102(d)(3)(iii), if applicable. The

owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(7).

(h) Within 30 days of completion of closure of the CCR unit, the owner or operator must prepare a notification of closure of a CCR unit. The notification must include the certification by a qualified professional engineer as required by § 257.102(f)(3). The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(8).

(i) *Deed notations.* (1) Except as provided by paragraph (i)(4) of this section, following closure of a CCR unit, the owner or operator must record a notation on the deed to the property, or some other instrument that is normally examined during title search.

(2) The notation on the deed must in perpetuity notify any potential purchaser of the property that:

(i) The land has been used as a CCR unit; and

(ii) Its use is restricted under the post-closure care requirements as provided by § 257.104(d)(1)(iii).

(3) Within 30 days of recording a notation on the deed to the property, the owner or operator must prepare a notification stating that the notation has been recorded. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(9).

(4) An owner or operator that closes a CCR unit in accordance with paragraph (c) of this section is not subject to the requirements of paragraphs (i)(1) through (3) of this section.

(j) The owner or operator of the CCR unit must comply with the closure recordkeeping requirements specified in § 257.105(i), the closure notification requirements specified in § 257.106(i), and the closure Internet requirements specified in § 257.107(i).

(k) *Criteria to retrofit an existing CCR surface impoundment.* (1) To retrofit an existing CCR surface impoundment, the owner or operator must:

(i) First remove all CCR, including any contaminated soils and sediments from the CCR unit; and

(ii) Comply with the requirements in § 257.72.

(iii) A CCR surface impoundment undergoing a retrofit remains subject to all other requirements of this subpart, including the requirement to conduct any necessary corrective action.

(2) *Written retrofit plan*—(i) *Content of the plan.* The owner or operator must prepare a written retrofit plan that describes the steps necessary to retrofit the CCR unit consistent with recognized and generally accepted good engineering practices. The written retrofit plan must include, at a minimum, all of the following information:

(A) A narrative description of the specific measures that will be taken to retrofit the CCR unit in accordance with this section.

(B) A description of the procedures to remove all CCR and contaminated soils and sediments from the CCR unit.

(C) An estimate of the maximum amount of CCR that will be removed as part of the retrofit operation.

(D) An estimate of the largest area of the CCR unit that will be affected by the retrofit operation.

(E) A schedule for completing all activities necessary to satisfy the retrofit criteria in this section, including an estimate of the year in which retrofit activities of the CCR unit will be completed.

(ii) *Timeframes for preparing the initial written retrofit plan.* (A) No later than 60 days prior to date of initiating retrofit activities, the owner or operator must prepare an initial written retrofit plan consistent with the requirements specified in paragraph (k)(2) of this section. For purposes of this subpart, initiation of retrofit activities has commenced if the owner or operator has ceased placing waste in the unit and completes any of the following actions or activities:

(*1*) Taken any steps necessary to implement the written retrofit plan;

(*2*) Submitted a completed application for any required state or agency permit or permit modification; or

(*3*) Taken any steps necessary to comply with any state or other agency standards that are a prerequisite, or are otherwise applicable, to initiating or completing the retrofit of a CCR unit.

(B) The owner or operator has completed the written retrofit plan when the plan, including the certification required by paragraph (k)(2)(iv) of this section, has been placed in the facility's operating record as required by § 257.105(j)(1).

(iii) *Amendment of a written retrofit plan.* (A) The owner or operator may amend the initial or any subsequent written retrofit plan at any time.

(B) The owner or operator must amend the written retrofit plan whenever:

(*1*) There is a change in the operation of the CCR unit that would substantially affect the written retrofit plan in effect; or

(*2*) Before or after retrofit activities have commenced, unanticipated events necessitate a revision of the written retrofit plan.

(C) The owner or operator must amend the retrofit plan at least 60 days prior to a planned change in the operation of the facility or CCR unit, or no later than 60 days after an unanticipated event requires the revision of an existing written retrofit plan. If a written retrofit plan is revised after retrofit activities have commenced for a CCR unit, the owner or operator must amend the current retrofit plan no later than 30 days following the triggering event.

(iv) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer that the activities outlined in the written retrofit plan, including any amendment of the plan, meet the requirements of this section.

(3) *Deadline for completion of activities related to the retrofit of a CCR unit.* Any CCR surface impoundment that is being retrofitted must complete all retrofit activities within the same time frames and procedures specified for the closure of a CCR surface impoundment in § 257.102(f) or, where applicable, § 257.103.

(4) Upon completion, the owner or operator must obtain a certification from a qualified professional engineer verifying that the retrofit activities have been completed in accordance with the retrofit plan specified in paragraph (k)(2) of this section and the requirements of this section.

(5) No later than the date the owner or operator initiates the retrofit of a CCR unit, the owner or operator must prepare a notification of intent to retrofit a CCR unit. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(j)(5).

(6) Within 30 days of completing the retrofit activities specified in paragraph (k)(1) of this section, the owner or operator must prepare a notification of completion of retrofit activities. The notification must include the certification by a qualified professional engineer as required by paragraph (k)(4) of this section. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(j)(6).

(7) At any time after the initiation of a CCR unit retrofit, the owner or operator may cease the retrofit and initiate closure of the CCR unit in accordance with the requirements of § 257.102.

(8) The owner or operator of the CCR unit must comply with the retrofit recordkeeping requirements specified in

§ 257.105(j), the retrofit notification requirements specified in § 257.106(j), and the retrofit Internet requirements specified in § 257.107(j).

§ 257.103 Alternative closure requirements.

The owner or operator of a CCR landfill, CCR surface impoundment, or any lateral expansion of a CCR unit that is subject to closure pursuant to § 257.101(a), (b)(1), or (d) may continue to receive CCR in the unit provided the owner or operator meets the requirements of either paragraph (a) or (b) of this section.

(a)(1) *No alternative CCR disposal capacity.* Notwithstanding the provisions of § 257.101(a), (b)(1), or (d), a CCR unit may continue to receive CCR if the owner or operator of the CCR unit certifies that the CCR must continue to be managed in that CCR unit due to the absence of alternative disposal capacity both on-site and off-site of the facility. To qualify under this paragraph (a)(1), the owner or operator of the CCR unit must document that all of the following conditions have been met:

(i) No alternative disposal capacity is available on-site or off-site. An increase in costs or the inconvenience of existing capacity is not sufficient to support qualification under this section;

(ii) The owner or operator has made, and continues to make, efforts to obtain additional capacity. Qualification under this subsection lasts only as long as no alternative capacity is available. Once alternative capacity is identified, the owner or operator must arrange to use such capacity as soon as feasible;

(iii) The owner or operator must remain in compliance with all other requirements of this subpart, including the requirement to conduct any necessary corrective action; and

(iv) The owner or operator must prepare an annual progress report documenting the continued lack of alternative capacity and the progress towards the development of alternative CCR disposal capacity.

(2) Once alternative capacity is available, the CCR unit must cease receiving CCR and initiate closure following the timeframes in § 257.102(e) and (f).

(3) If no alternative capacity is identified within five years after the initial certification, the CCR unit must cease receiving CCR and close in accordance with the timeframes in § 257.102(e) and (f).

(b)(1) *Permanent cessation of a coal-fired boiler(s) by a date certain.* Notwithstanding the provisions of § 257.101(a), (b)(1), and (d), a CCR unit may continue to receive CCR if the owner or operator certifies that the facility will cease operation of the coal-fired boilers within the timeframes specified in paragraphs (b)(2) through (4) of this section, but in the interim period (prior to closure of the coal-fired boiler), the facility must continue to use the CCR unit due to the absence of alternative disposal capacity both on-site and off-site of the facility. To qualify under this paragraph (b)(1), the owner or operator of the CCR unit must document that all of the following conditions have been met:

(i) No alternative disposal capacity is available on-site or off-site. An increase in costs or the inconvenience of existing capacity is not sufficient to support qualification under this section.

(ii) The owner or operator must remain in compliance with all other requirements of this subpart, including the requirement to conduct any necessary corrective action; and

(iii) The owner or operator must prepare an annual progress report documenting the continued lack of alternative capacity and the progress towards the closure of the coal-fired boiler.

(2) For a CCR surface impoundment that is 40 acres or smaller, the coal-fired boiler must cease operation and the CCR surface impoundment must have completed closure no later than October 17, 2023.

(3) For a CCR surface impoundment that is larger than 40 acres, the coal-fired boiler must cease operation, and the CCR surface impoundment must complete closure no later than October 17, 2028.

(4) For a CCR landfill, the coal-fired boiler must cease operation, and the CCR landfill must complete closure no later than April 19, 2021.

(c) Required notices and progress reports. An owner or operator of a CCR unit that closes in accordance with paragraphs (a) or (b) of this section must complete the notices and progress reports specified in paragraphs (c)(1) through (3) of this section.

(1) Within six months of becoming subject to closure pursuant to § 257.101(a), (b)(1), or (d), the owner or operator must prepare and place in the facility's operating record a notification of intent to comply with the alternative closure requirements of this section. The notification must describe why the CCR unit qualifies for the alternative closure provisions under either paragraph (a) or (b) of this section, in addition to providing the documentation and certifications required by paragraph (a) or (b) of this section.

(2) The owner or operator must prepare the periodic progress reports required by paragraphs (a)(1)(iv) or (b)(1)(iii), in addition to describing any problems encountered and a description of the actions taken to resolve the problems. The annual progress reports must be completed according to the following schedule:

(i) The first annual progress report must be prepared no later than 13 months after completing the notification of intent to comply with the alternative closure requirements required by paragraph (c)(1) of this section.

(ii) The second annual progress report must be prepared no later than 12 months after completing the first annual progress report. Additional annual progress reports must be prepared within 12 months of completing the previous annual progress report.

(iii) The owner or operator has completed the progress reports specified in paragraph (c)(2) of this section when the reports are placed in the facility's operating record as required by § 257.105(i)(10).

(3) An owner or operator of a CCR unit must also prepare the notification of intent to close a CCR unit as required by § 257.102(g).

(d) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(i), the notification requirements specified in § 257.106(i), and the Internet requirements specified in § 257.107(i).

§ 257.104 Post-closure care requirements.

(a) *Applicability.* (1) Except as provided by either paragraph (a)(2) or (3) of this section, § 257.104 applies to the owners or operators of CCR landfills, CCR surface impoundments, and all lateral expansions of CCR units that are subject to the closure criteria under § 257.102.

(2) An owner or operator of a CCR unit that elects to close a CCR unit by removing CCR as provided by § 257.102(c) is not subject to the post-closure care criteria under this section.

(3) An owner or operator of an inactive CCR surface impoundment that elects to close a CCR unit pursuant to the requirements under § 257.100(b) is not subject to the post-closure care criteria under this section.

(b) *Post-closure care maintenance requirements.* Following closure of the CCR unit, the owner or operator must conduct post-closure care for the CCR unit, which must consist of at least the following:

(1) Maintaining the integrity and effectiveness of the final cover system, including making repairs to the final

cover as necessary to correct the effects of settlement, subsidence, erosion, or other events, and preventing run-on and run-off from eroding or otherwise damaging the final cover;

(2) If the CCR unit is subject to the design criteria under § 257.70, maintaining the integrity and effectiveness of the leachate collection and removal system and operating the leachate collection and removal system in accordance with the requirements of § 257.70; and

(3) Maintaining the groundwater monitoring system and monitoring the groundwater in accordance with the requirements of §§ 257.90 through 257.98.

(c) *Post-closure care period.* (1) Except as provided by paragraph (c)(2) of this section, the owner or operator of the CCR unit must conduct post-closure care for 30 years.

(2) If at the end of the post-closure care period the owner or operator of the CCR unit is operating under assessment monitoring in accordance with § 257.95, the owner or operator must continue to conduct post-closure care until the owner or operator returns to detection monitoring in accordance with § 257.95.

(d) *Written post-closure plan*—(1) *Content of the plan.* The owner or operator of a CCR unit must prepare a written post-closure plan that includes, at a minimum, the information specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) A description of the monitoring and maintenance activities required in paragraph (b) of this section for the CCR unit, and the frequency at which these activities will be performed;

(ii) The name, address, telephone number, and email address of the person or office to contact about the facility during the post-closure care period; and

(iii) A description of the planned uses of the property during the post-closure period. Post-closure use of the property shall not disturb the integrity of the final cover, liner(s), or any other component of the containment system, or the function of the monitoring systems unless necessary to comply with the requirements in this subpart. Any other disturbance is allowed if the owner or operator of the CCR unit demonstrates that disturbance of the final cover, liner, or other component of the containment system, including any removal of CCR, will not increase the potential threat to human health or the environment. The demonstration must be certified by a qualified professional engineer, and notification shall be provided to the State Director that the demonstration has been placed in the operating record and on the owners or operator's publicly accessible Internet site.

(2) *Deadline to prepare the initial written post-closure plan*—(i) *Existing CCR landfills and existing CCR surface impoundments.* No later than October 17, 2016, the owner or operator of the CCR unit must prepare an initial written post-closure plan consistent with the requirements specified in paragraph (d)(1) of this section.

(ii) *New CCR landfills, new CCR surface impoundments, and any lateral expansion of a CCR unit.* No later than the date of the initial receipt of CCR in the CCR unit, the owner or operator must prepare an initial written post-closure plan consistent with the requirements specified in paragraph (d)(1) of this section.

(iii) The owner or operator has completed the written post-closure plan when the plan, including the certification required by paragraph (d)(4) of this section, has been placed in the facility's operating record as required by § 257.105(i)(4).

(3) *Amendment of a written post-closure plan.* (i) The owner or operator may amend the initial or any subsequent written post-closure plan developed pursuant to paragraph (d)(1) of this section at any time.

(ii) The owner or operator must amend the written closure plan whenever:

(A) There is a change in the operation of the CCR unit that would substantially affect the written post-closure plan in effect; or

(B) After post-closure activities have commenced, unanticipated events necessitate a revision of the written post-closure plan.

(iii) The owner or operator must amend the written post-closure plan at least 60 days prior to a planned change in the operation of the facility or CCR unit, or no later than 60 days after an unanticipated event requires the need to revise an existing written post-closure plan. If a written post-closure plan is revised after post-closure activities have commenced for a CCR unit, the owner or operator must amend the written post-closure plan no later than 30 days following the triggering event.

(4) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer that the initial and any amendment of the written post-closure plan meets the requirements of this section.

(e) *Notification of completion of post-closure care period.* No later than 60 days following the completion of the post-closure care period, the owner or operator of the CCR unit must prepare a notification verifying that post-closure care has been completed. The notification must include the certification by a qualified professional engineer verifying that post-closure care has been completed in accordance with the closure plan specified in paragraph (d) of this section and the requirements of this section. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(13).

(f) The owner or operator of the CCR unit must comply with the recordkeeping requirements specified in § 257.105(i), the notification requirements specified in § 257.106(i), and the Internet requirements specified in § 257.107(i).

Recordkeeping, Notification, and Posting of Information to the Internet

§ 257.105 Recordkeeping requirements.

(a) Each owner or operator of a CCR unit subject to the requirements of this subpart must maintain files of all information required by this section in a written operating record at their facility.

(b) Unless specified otherwise, each file must be retained for at least five years following the date of each occurrence, measurement, maintenance, corrective action, report, record, or study.

(c) An owner or operator of more than one CCR unit subject to the provisions of this subpart may comply with the requirements of this section in one recordkeeping system provided the system identifies each file by the name of each CCR unit. The files may be maintained on microfilm, on a computer, on computer disks, on a storage system accessible by a computer, on magnetic tape disks, or on microfiche.

(d) The owner or operator of a CCR unit must submit to the State Director and/or appropriate Tribal authority any demonstration or documentation required by this subpart, if requested, when such information is not otherwise available on the owner or operator's publicly accessible Internet site.

(e) *Location restrictions.* The owner or operator of a CCR unit subject to this subpart must place the demonstrations documenting whether or not the CCR unit is in compliance with the requirements under §§ 257.60(a), 257.61(a), 257.62(a), 257.63(a), and 257.64(a), as it becomes available, in the facility's operating record.

(f) *Design criteria.* The owner or operator of a CCR unit subject to this subpart must place the following

information, as it becomes available, in the facility's operating record:

(1) The design and construction certifications as required by § 257.70(e) and (f).

(2) The documentation of liner type as required by § 257.71(a).

(3) The design and construction certifications as required by § 257.72(c) and (d).

(4) Documentation prepared by the owner or operator stating that the permanent identification marker was installed as required by §§ 257.73(a)(1) and 257.74(a)(1).

(5) The initial and periodic hazard potential classification assessments as required by §§ 257.73(a)(2) and 257.74(a)(2).

(6) The emergency action plan (EAP), and any amendment of the EAP, as required by §§ 257.73(a)(3) and 257.74(a)(3), except that only the most recent EAP must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(7) Documentation prepared by the owner or operator recording the annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders as required by §§ 257.73(a)(3)(i)(E) and 257.74(a)(3)(i)(E).

(8) Documentation prepared by the owner or operator recording all activations of the emergency action plan as required by §§ 257.73(a)(3)(v) and 257.74(a)(3)(v).

(9) The history of construction, and any revisions of it, as required by § 257.73(c), except that these files must be maintained until the CCR unit completes closure of the unit in accordance with § 257.102.

(10) The initial and periodic structural stability assessments as required by §§ 257.73(d) and 257.74(d).

(11) Documentation detailing the corrective measures taken to remedy the deficiency or release as required by §§ 257.73(d)(2) and 257.74(d)(2).

(12) The initial and periodic safety factor assessments as required by §§ 257.73(e) and 257.74(e).

(13) The design and construction plans, and any revisions of it, as required by § 257.74(c), except that these files must be maintained until the CCR unit completes closure of the unit in accordance with § 257.102.

(g) *Operating criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

(1) The CCR fugitive dust control plan, and any subsequent amendment of the plan, required by § 257.80(b), except that only the most recent control plan must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(2) The annual CCR fugitive dust control report required by § 257.80(c).

(3) The initial and periodic run-on and run-off control system plans as required by § 257.81(c).

(4) The initial and periodic inflow design flood control system plan as required by § 257.82(c).

(5) Documentation recording the results of each inspection and instrumentation monitoring by a qualified person as required by § 257.83(a).

(6) The periodic inspection report as required by § 257.83(b)(2).

(7) Documentation detailing the corrective measures taken to remedy the deficiency or release as required by §§ 257.83(b)(5) and 257.84(b)(5).

(8) Documentation recording the results of the weekly inspection by a qualified person as required by § 257.84(a).

(9) The periodic inspection report as required by § 257.84(b)(2).

(h) *Groundwater monitoring and corrective action.* The owner or operator of a CCR unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

(1) The annual groundwater monitoring and corrective action report as required by § 257.90(e).

(2) Documentation of the design, installation, development, and decommissioning of any monitoring wells, piezometers and other measurement, sampling, and analytical devices as required by § 257.91(e)(1).

(3) The groundwater monitoring system certification as required by § 257.91(f).

(4) The selection of a statistical method certification as required by § 257.93(f)(6).

(5) Within 30 days of establishing an assessment monitoring program, the notification as required by § 257.94(e)(3).

(6) The results of appendices III and IV to this part constituent concentrations as required by § 257.95(d)(1).

(7) Within 30 days of returning to a detection monitoring program, the notification as required by § 257.95(e).

(8) Within 30 days of detecting one or more constituents in appendix IV to this part at statistically significant levels above the groundwater protection standard, the notifications as required by § 257.95(g).

(9) Within 30 days of initiating the assessment of corrective measures requirements, the notification as required by § 257.95(g)(5).

(10) The completed assessment of corrective measures as required by § 257.96(d).

(11) Documentation prepared by the owner or operator recording the public meeting for the corrective measures assessment as required by § 257.96(e).

(12) The semiannual report describing the progress in selecting and designing the remedy and the selection of remedy report as required by § 257.97(a), except that the selection of remedy report must be maintained until the remedy has been completed.

(13) Within 30 days of completing the remedy, the notification as required by § 257.98(e).

(i) *Closure and post-closure care.* The owner or operator of a CCR unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

(1) The notification of intent to initiate closure of the CCR unit as required by § 257.100(c)(1).

(2) The annual progress reports of closure implementation as required by § 257.100(c)(2)(i) and (ii).

(3) The notification of closure completion as required by § 257.100(c)(3).

(4) The written closure plan, and any amendment of the plan, as required by § 257.102(b), except that only the most recent closure plan must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(5) The written demonstration(s), including the certification required by § 257.102(e)(2)(iii), for a time extension for initiating closure as required by § 257.102(e)(2)(ii).

(6) The written demonstration(s), including the certification required by § 257.102(f)(2)(iii), for a time extension for completing closure as required by § 257.102(f)(2)(i).

(7) The notification of intent to close a CCR unit as required by § 257.102(g).

(8) The notification of completion of closure of a CCR unit as required by § 257.102(h).

(9) The notification recording a notation on the deed as required by § 257.102(i).

(10) The notification of intent to comply with the alternative closure requirements as required by § 257.103(c)(1).

(11) The annual progress reports under the alternative closure requirements as required by § 257.103(c)(2).

(12) The written post-closure plan, and any amendment of the plan, as required by § 257.104(d), except that only the most recent closure plan must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(13) The notification of completion of post-closure care period as required by § 257.104(e).

(j) *Retrofit criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

(1) The written retrofit plan, and any amendment of the plan, as required by § 257.102(k)(2), except that only the most recent retrofit plan must be maintained in the facility's operating record irrespective of the time requirement specified in paragraph (b) of this section.

(2) The notification of intent that the retrofit activities will proceed in accordance with the alternative procedures in § 257.103.

(3) The annual progress reports required under the alternative requirements as required by § 257.103.

(4) The written demonstration(s), including the certification in § 257.102(f)(2)(iii), for a time extension for completing retrofit activities as required by § 257.102(k)(3).

(5) The notification of intent to initiate retrofit of a CCR unit as required by § 257.102(k)(5).

(6) The notification of completion of retrofit activities as required by § 257.102(k)(6).

§ 257.106 Notification requirements.

(a) The notifications required under paragraphs (e) through (i) of this section must be sent to the relevant State Director and/or appropriate Tribal authority before the close of business on the day the notification is required to be completed. For purposes of this section, *before the close of business* means the notification must be postmarked or sent by electronic mail (email). If a notification deadline falls on a weekend or federal holiday, the notification deadline is automatically extended to the next business day.

(b) If any CCR unit is located in its entirety within Indian Country, the notifications of this section must be sent to the appropriate Tribal authority. If any CCR unit is located in part within Indian Country, the notifications of this section must be sent both to the appropriate State Director and Tribal authority.

(c) Notifications may be combined as long as the deadline requirement for each notification is met.

(d) Unless otherwise required in this section, the notifications specified in this section must be sent to the State Director and/or appropriate Tribal authority within 30 days of placing in the operating record the information required by § 257.105.

(e) *Location restrictions.* The owner or operator of a CCR unit subject to the requirements of this subpart must notify the State Director and/or appropriate Tribal authority that each demonstration specified under § 257.105(e) has been placed in the operating record and on the owner or operator's publicly accessible internet site.

(f) *Design criteria.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

(1) Within 60 days of commencing construction of a new CCR unit, provide notification of the availability of the design certification specified under § 257.105(f)(1) or (3). If the owner or operator of the CCR unit elects to install an alternative composite liner, the owner or operator must also submit to the State Director and/or appropriate Tribal authority a copy of the alternative composite liner design.

(2) No later than the date of initial receipt of CCR by a new CCR unit, provide notification of the availability of the construction certification specified under § 257.105(f)(1) or (3).

(3) Provide notification of the availability of the documentation of liner type specified under § 257.105(f)(2).

(4) Provide notification of the availability of the initial and periodic hazard potential classification assessments specified under § 257.105(f)(5).

(5) Provide notification of the availability of emergency action plan (EAP), and any revisions of the EAP, specified under § 257.105(f)(6).

(6) Provide notification of the availability of documentation prepared by the owner or operator recording the annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders specified under § 257.105(f)(7).

(7) Provide notification of documentation prepared by the owner or operator recording all activations of the emergency action plan specified under § 257.105(f)(8).

(8) Provide notification of the availability of the history of construction, and any revision of it, specified under § 257.105(f)(9).

(9) Provide notification of the availability of the initial and periodic structural stability assessments specified under § 257.105(f)(10).

(10) Provide notification of the availability of the documentation detailing the corrective measures taken to remedy the deficiency or release specified under § 257.105(f)(11).

(11) Provide notification of the availability of the initial and periodic safety factor assessments specified under § 257.105(f)(12).

(12) Provide notification of the availability of the design and construction plans, and any revision of them, specified under § 257.105(f)(13).

(g) *Operating criteria.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

(1) Provide notification of the availability of the CCR fugitive dust control plan, or any subsequent amendment of the plan, specified under § 257.105(g)(1).

(2) Provide notification of the availability of the annual CCR fugitive dust control report specified under § 257.105(g)(2).

(3) Provide notification of the availability of the initial and periodic run-on and run-off control system plans specified under § 257.105(g)(3).

(4) Provide notification of the availability of the initial and periodic inflow design flood control system plans specified under § 257.105(g)(4).

(5) Provide notification of the availability of the periodic inspection reports specified under § 257.105(g)(6).

(6) Provide notification of the availability of the documentation detailing the corrective measures taken to remedy the deficiency or release specified under § 257.105(g)(7).

(7) Provide notification of the availability of the periodic inspection reports specified under § 257.105(g)(9).

(h) *Groundwater monitoring and corrective action.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

(1) Provide notification of the availability of the annual groundwater

monitoring and corrective action report specified under § 257.105(h)(1).

(2) Provide notification of the availability of the groundwater monitoring system certification specified under § 257.105(h)(3).

(3) Provide notification of the availability of the selection of a statistical method certification specified under § 257.105(h)(4).

(4) Provide notification that an assessment monitoring programs has been established specified under § 257.105(h)(5).

(5) Provide notification that the CCR unit is returning to a detection monitoring program specified under § 257.105(h)(7).

(6) Provide notification that one or more constituents in appendix IV to this part have been detected at statistically significant levels above the groundwater protection standard and the notifications to land owners specified under § 257.105(h)(8).

(7) Provide notification that an assessment of corrective measures has been initiated specified under § 257.105(h)(9).

(8) Provide notification of the availability of assessment of corrective measures specified under § 257.105(h)(10).

(9) Provide notification of the availability of the semiannual report describing the progress in selecting and designing the remedy and the selection of remedy report specified under § 257.105(h)(12).

(10) Provide notification of the completion of the remedy specified under § 257.105(h)(13).

(i) *Closure and post-closure care.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible Internet site. The owner or operator must:

(1) Provide notification of the intent to initiate closure of the CCR unit specified under § 257.105(i)(1).

(2) Provide notification of the availability of the annual progress reports of closure implementation specified under § 257.105(i)(2).

(3) Provide notification of closure completion specified under § 257.105(i)(3).

(4) Provide notification of the availability of the written closure plan, and any amendment of the plan, specified under § 257.105(i)(4).

(5) Provide notification of the availability of the demonstration(s) for a time extension for initiating closure specified under § 257.105(i)(5).

(6) Provide notification of the availability of the demonstration(s) for a time extension for completing closure specified under § 257.105(i)(6).

(7) Provide notification of intent to close a CCR unit specified under § 257.105(i)(7).

(8) Provide notification of completion of closure of a CCR unit specified under § 257.105(i)(8).

(9) Provide notification of the deed notation as required by § 257.105(i)(9).

(10) Provide notification of intent to comply with the alternative closure requirements specified under § 257.105(i)(10).

(11) The annual progress reports under the alternative closure requirements as required by § 257.105(i)(11).

(12) Provide notification of the availability of the written post-closure plan, and any amendment of the plan, specified under § 257.105(i)(12).

(13) Provide notification of completion of post-closure care specified under § 257.105(i)(13).

(j) *Retrofit criteria.* The owner or operator of a CCR unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible Internet site. The owner or operator must:

(1) Provide notification of the availability of the written retrofit plan, and any amendment of the plan, specified under § 257.105(j)(1).

(2) Provide notification of intent to comply with the alternative retrofit requirements specified under § 257.105(j)(2).

(3) The annual progress reports under the alternative retrofit requirements as required by § 257.105(j)(3).

(4) Provide notification of the availability of the demonstration(s) for a time extension for completing retrofit activities specified under § 257.105(j)(4).

(5) Provide notification of intent to initiate retrofit of a CCR unit specified under § 257.105(j)(5).

(6) Provide notification of completion of retrofit activities specified under § 257.105(j)(6).

§ 257.107 Publicly accessible Internet site requirements.

(a) Each owner or operator of a CCR unit subject to the requirements of this subpart must maintain a publicly accessible Internet site (CCR Web site) containing the information specified in this section. The owner or operator's Web site must be titled ''CCR Rule Compliance Data and Information.''

(b) An owner or operator of more than one CCR unit subject to the provisions of this subpart may comply with the requirements of this section by using the same Internet site for multiple CCR units provided the CCR Web site clearly delineates information by the name or identification number of each unit.

(c) Unless otherwise required in this section, the information required to be posted to the CCR Web site must be made available to the public for at least five years following the date on which the information was first posted to the CCR Web site.

(d) Unless otherwise required in this section, the information must be posted to the CCR Web site within 30 days of placing the pertinent information required by § 257.105 in the operating record.

(e) *Location restrictions.* The owner or operator of a CCR unit subject to this subpart must place each demonstration specified under § 257.105(e) on the owner or operator's CCR Web site.

(f) *Design criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) Within 60 days of commencing construction of a new unit, the design certification specified under § 257.105(f)(1) or (3).

(2) No later than the date of initial receipt of CCR by a new CCR unit, the construction certification specified under § 257.105(f)(1) or (3).

(3) The documentation of liner type specified under § 257.105(f)(2).

(4) The initial and periodic hazard potential classification assessments specified under § 257.105(f)(5).

(5) The emergency action plan (EAP) specified under § 257.105(f)(6), except that only the most recent EAP must be maintained on the CCR Web site irrespective of the time requirement specified in paragraph (c) of this section.

(6) Documentation prepared by the owner or operator recording the annual face-to-face meeting or exercise between representatives of the owner or operator of the CCR unit and the local emergency responders specified under § 257.105(f)(7).

(7) Documentation prepared by the owner or operator recording any activation of the emergency action plan specified under § 257.105(f)(8).

(8) The history of construction, and any revisions of it, specified under § 257.105(f)(9).

(9) The initial and periodic structural stability assessments specified under § 257.105(f)(10).

(10) The documentation detailing the corrective measures taken to remedy the

deficiency or release specified under § 257.105(f)(11).

(11) The initial and periodic safety factor assessments specified under § 257.105(f)(12).

(12) The design and construction plans, and any revisions of them, specified under § 257.105(f)(13).

(g) *Operating criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) The CCR fugitive dust control plan, or any subsequent amendment of the plan, specified under § 257.105(g)(1) except that only the most recent plan must be maintained on the CCR Web site irrespective of the time requirement specified in paragraph (c) of this section.

(2) The annual CCR fugitive dust control report specified under § 257.105(g)(2).

(3) The initial and periodic run-on and run-off control system plans specified under § 257.105(g)(3).

(4) The initial and periodic inflow design flood control system plans specified under § 257.105(g)(4).

(5) The periodic inspection reports specified under § 257.105(g)(6).

(6) The documentation detailing the corrective measures taken to remedy the deficiency or release specified under § 257.105(g)(7).

(7) The periodic inspection reports specified under § 257.105(g)(9).

(h) *Groundwater monitoring and corrective action.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) The annual groundwater monitoring and corrective action report specified under § 257.105(h)(1).

(2) The groundwater monitoring system certification specified under § 257.105(h)(3).

(3) The selection of a statistical method certification specified under § 257.105(h)(4).

(4) The notification that an assessment monitoring programs has been established specified under § 257.105(h)(5).

(5) The notification that the CCR unit is returning to a detection monitoring program specified under § 257.105(h)(7).

(6) The notification that one or more constituents in appendix IV to this part have been detected at statistically significant levels above the groundwater protection standard and the notifications to land owners specified under § 257.105(h)(8).

(7) The notification that an assessment of corrective measures has been initiated specified under § 257.105(h)(9).

(8) The assessment of corrective measures specified under § 257.105(h)(10).

(9) The semiannual reports describing the progress in selecting and designing remedy and the selection of remedy report specified under § 257.105(h)(12), except that the selection of the remedy report must be maintained until the remedy has been completed.

(10) The notification that the remedy has been completed specified under § 257.105(h)(13).

(i) *Closure and post-closure care.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) The notification of intent to initiate closure of the CCR unit specified under § 257.105(i)(1).

(2) The annual progress reports of closure implementation specified under § 257.105(i)(2).

(3) The notification of closure completion specified under § 257.105(i)(3).

(4) The written closure plan, and any amendment of the plan, specified under § 257.105(i)(4).

(5) The demonstration(s) for a time extension for initiating closure specified under § 257.105(i)(5).

(6) The demonstration(s) for a time extension for completing closure specified under § 257.105(i)(6).

(7) The notification of intent to close a CCR unit specified under § 257.105(i)(7).

(8) The notification of completion of closure of a CCR unit specified under § 257.105(i)(8).

(9) The notification recording a notation on the deed as required by § 257.105(i)(9).

(10) The notification of intent to comply with the alternative closure requirements as required by § 257.105(i)(10).

(11) The annual progress reports under the alternative closure requirements as required by § 257.105(i)(11).

(12) The written post-closure plan, and any amendment of the plan, specified under § 257.105(i)(12).

(13) The notification of completion of post-closure care specified under § 257.105(i)(13).

(j) *Retrofit criteria.* The owner or operator of a CCR unit subject to this subpart must place the following information on the owner or operator's CCR Web site:

(1) The written retrofit plan, and any amendment of the plan, specified under § 257.105(j)(1).

(2) The notification of intent to comply with the alternative retrofit requirements as required by § 257.105(j)(2).

(3) The annual progress reports under the alternative retrofit requirements as required by § 257.105(j)(3).

(4) The demonstration(s) for a time extension for completing retrofit activities specified under § 257.105(j)(4).

(5) The notification of intent to retrofit a CCR unit specified under § 257.105(j)(5).

(6) The notification of completion of retrofit activities specified under § 257.105(j)(6).

■ 5. Amend part 257 by adding ''Appendix III to Part 257'' and ''Appendix IV to Part 257'' to read as follows:

Appendix III to Part 257—Constituents for Detection Monitoring

Common name [1]
Boron
Calcium
Chloride
Fluoride
pH
Sulfate
Total Dissolved Solids (TDS)

[1] Common names are those widely used in government regulations, scientific publications, and commerce; synonyms exist for many chemicals.

Appendix IV to Part 257—Constituents for Assessment Monitoring

Common name [1]
Antimony
Arsenic
Barium
Beryllium
Cadmium
Chromium
Cobalt
Fluoride
Lead
Lithium
Mercury
Molybdenum
Selenium
Thallium
Radium 226 and 228 combined

[1] Common names are those widely used in government regulations, scientific publications, and commerce; synonyms exist for many chemicals.

PART 261—IDENTIFICATION AND LISTING OF HAZARDOUS WASTE

■ 6. The authority citation for part 261 continues to read as follows:

Authority: 42 U.S.C. 6905, 6912(a), 6921, 6922, 6924(y) and 6938.

■ 7. Section 261.4 is amended by revising paragraph (b)(4) to read as follows:

§ 261.4 Exclusions.

* * * * *

(b) * * *

(4)(i) Fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels, except as provided by § 266.112 of this chapter for facilities that burn or process hazardous waste.

(ii) The following wastes generated primarily from processes that support the combustion of coal or other fossil fuels that are co-disposed with the wastes in paragraph (b)(4)(i) of this section, except as provided by § 266.112 of this chapter for facilities that burn or process hazardous waste:

(A) *Coal pile run-off.* For purposes of paragraph (b)(4) of this section, coal pile run-off means any precipitation that drains off coal piles.

(B) *Boiler cleaning solutions.* For purposes of paragraph (b)(4) of this section, boiler cleaning solutions means water solutions and chemical solutions used to clean the fire-side and water-side of the boiler.

(C) *Boiler blowdown.* For purposes of paragraph (b)(4) of this section, boiler blowdown means water purged from boilers used to generate steam.

(D) *Process water treatment and demineralizer regeneration wastes.* For purposes of paragraph (b)(4) of this section, process water treatment and demineralizer regeneration wastes means sludges, rinses, and spent resins generated from processes to remove dissolved gases, suspended solids, and dissolved chemical salts from combustion system process water.

(E) *Cooling tower blowdown.* For purposes of paragraph (b)(4) of this section, cooling tower blowdown means water purged from a closed cycle cooling system. Closed cycle cooling systems include cooling towers, cooling ponds, or spray canals.

(F) *Air heater and precipitator washes.* For purposes of paragraph (b)(4) of this section, air heater and precipitator washes means wastes from cleaning air preheaters and electrostatic precipitators.

(G) *Effluents from floor and yard drains and sumps.* For purposes of paragraph (b)(4) of this section, effluents from floor and yard drains and sumps means wastewaters, such as wash water, collected by or from floor drains, equipment drains, and sumps located inside the power plant building; and wastewaters, such as rain runoff, collected by yard drains and sumps located outside the power plant building.

(H) *Wastewater treatment sludges.* For purposes of paragraph (b)(4) of this section, wastewater treatment sludges refers to sludges generated from the treatment of wastewaters specified in paragraphs (b)(4)(ii)(A) through (F) of this section.

* * * * *

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residents within one mile of landfills to those percentages in the general population, EPA found that minority and low-income residents make up a smaller percentage of the populations near landfills than they do in the general population, *i.e.,* minorities comprised 16.6 percent of the population near landfills versus 24.8 percent nationwide and low-income residents comprised 8.6 percent of the population near landfills versus 11.3 percent nationwide. In summary, although populations within the catchment areas of plants with surface impoundments appear to have disproportionately high percentages of minority and low-income residents relative to the nationwide average, populations surrounding plants with landfills do not. Because landfills are less likely than impoundments to experience surface water run-off and releases, catchment areas were not considered for landfills.

The CCR rule is risk-reducing with reductions in risk occurring largely within the surface water catchment zones around, and groundwater beneath, coal-fired electric utility plants. Since the CCR rule is risk-reducing and this action does not add to risks, this action will not result in new disproportionate risks to minority or low-income populations.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 257

Environmental protection, Beneficial use, Coal combustion products, Coal combustion residuals, Coal combustion waste, Disposal, Hazardous waste, Landfill, Surface impoundment.

Dated: July 17, 2018.

Andrew R. Wheeler,

Acting Administrator.

For the reasons set out in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 257—CRITERIA FOR CLASSIFICATION OF SOLID WASTE DISPOSAL FACILITIES AND PRACTICES

■ 1. The authority citation for part 257 is revised to read as follows:

Authority: 42 U.S.C. 6907(a)(3), 6912(a)(1), 6944(a), 6945(d); 33 U.S.C. 1345(d) and (e).

■ 2. Section 257.53 is amended by adding the definitions of ''Nonparticipating State'', ''Participating State'', and ''Participating State Director'' in alphabetical order to read as follows:

§ 257.53 Definitions.

* * * * *

Nonparticipating State means a State—

(1) For which the Administrator has not approved a State permit program or other system of prior approval and conditions under RCRA section 4005(d)(1)(B);

(2) The Governor of which has not submitted to the Administrator for approval evidence to operate a State permit program or other system of prior approval and conditions under RCRA section 4005(d)(1)(A);

(3) The Governor of which provides notice to the Administrator that, not fewer than 90 days after the date on which the Governor provides the notice to the Administrator, the State will relinquish an approval under RCRA section 4005(d)(1)(B) to operate a permit program or other system of prior approval and conditions; or

(4) For which the Administrator has withdrawn approval for a permit program or other system of prior approval and conditions under RCRA section 4005(d)(1)(E).

* * * * *

Participating State means a state with a state program for control of CCR that has been approved pursuant to RCRA section 4005(d).

Participating State Director means the chief administrative officer of any state agency operating the CCR permit program in a participating state or the delegated representative of the Participating State Director. If responsibility is divided among two or more state agencies, Participating State Director means the chief administrative officer of the state agency authorized to perform the particular function or procedure to which reference is made.

* * * * *

■ 3. Section 257.60 is amended by revising paragraph (b) to read as follows:

§ 257.60 Placement above the uppermost aquifer.

* * * * *

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the demonstration meets the requirements of paragraph (a) of this section.

* * * * *

■ 4. Section 257.61 is amended by revising paragraph (b) to read as follows:

§ 257.61 Wetlands.

* * * * *

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the demonstration meets the requirements of paragraph (a) of this section.

* * * * *

■ 5. Section 257.62 is amended by revising paragraph (b) to read as follows:

§ 257.62 Fault areas.

* * * * *

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the demonstration meets the requirements of paragraph (a) of this section.

* * * * *

■ 6. Section 257.63 is amended by revising paragraph (b) to read as follows:

§ 257.63 Seismic impact zones.

* * * * *

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the demonstration meets the requirements of paragraph (a) of this section.

* * * * *

■ 7. Section 257.64 is amended by revising paragraph (c) to read as follows:

§ 257.64 Unstable areas.

* * * * *

(c) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the demonstration meets the requirements of paragraph (a) of this section.

* * * * *

■ 8. Section 257.70 is amended by revising paragraphs (c)(2), (e), and (f) to read as follows:

§ 257.70 Design criteria for new CCR landfills and any lateral expansion of a CCR landfill.

* * * * *

(c) * * *

(2) The owner or operator must obtain certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the liquid flow rate through the lower component of the alternative composite liner is no greater than the liquid flow rate through two feet of compacted soil with a hydraulic conductivity of $1x10^{-7}$ cm/sec. The hydraulic conductivity for the two feet of compacted soil used in the comparison shall be no greater than $1x10^{-7}$ cm/sec. The hydraulic conductivity of any alternative to the two feet of compacted soil must be determined using recognized and generally accepted methods. The liquid flow rate comparison must be made using Equation 1 of this section, which is derived from Darcy's Law for gravity flow through porous media.

(Eq. 1):

$$\frac{Q}{A} = q = k\left(\frac{h}{t} + 1\right)$$

Where:

Q = flow rate (cubic centimeters/second);
A = surface area of the liner (squared centimeters);
q = flow rate per unit area (cubic centimeters/second/squared centimeter);
k = hydraulic conductivity of the liner (centimeters/second);
h = hydraulic head above the liner (centimeters); and
t = thickness of the liner (centimeters).

* * * * *

(e) Prior to construction of the CCR landfill or any lateral expansion of a CCR landfill, the owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the design of the composite liner (or, if applicable, alternative composite liner) and the leachate collection and removal system meets the requirements of this section.

(f) Upon completion of construction of the CCR landfill or any lateral expansion of a CCR landfill, the owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the design of the composite liner (or, if applicable, alternative composite liner) and the leachate collection and removal system have been constructed in accordance with the requirements of this section.

* * * * *

■ 9. Section 257.71 is amended by revising paragraph (b) to read as follows:

§ 257.71 Liner design criteria for existing CCR surface impoundments.

* * * * *

(b) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority attesting that the documentation as to whether a CCR unit meets the requirements of paragraph (a) of this section is accurate.

* * * * *

■ 10. Section 257.72 is amended by revising paragraphs (c) and (d) to read as follows:

§ 257.72 Liner design criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment.

* * * * *

(c) Prior to construction of the CCR surface impoundment or any lateral expansion of a CCR surface impoundment, the owner or operator must obtain certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the design of the composite liner or, if applicable, the design of an alternative composite liner complies with the requirements of this section.

(d) Upon completion, the owner or operator must obtain certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the composite liner or if applicable, the alternative composite liner has been constructed in accordance with the requirements of this section.

* * * * *

■ 11. Section 257.80 is amended by revising paragraph (b)(7) to read as follows:

§ 257.80 Air criteria.

* * * * *

(b) * * *

(7) The owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the initial CCR fugitive dust control plan, or any subsequent amendment of it, meets the requirements of this section.

* * * * *

■ 12. Section 257.81 is amended by revising paragraph (c)(5) to read as follows:

§ 257.81 Run-on and run-off controls for CCR landfills.

* * * * *

(c) * * *

(5) The owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the initial and periodic run-on and run-off control system plans meet the requirements of this section.

* * * * *

■ 13. Section 257.82 is amended by revising paragraph (c)(5) to read as follows:

§ 257.82 Hydrologic and hydraulic capacity requirements for CCR surface impoundments.

* * * * *

(c) * * *

(5) The owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the initial and periodic inflow design flood control system plans meet the requirements of this section.

* * * * *

■ 14. Section 257.90 is amended by revising paragraph (a) and adding paragraph (g) to read as follows:

§ § 257.90 Applicability.

(a) All CCR landfills, CCR surface impoundments, and lateral expansions of CCR units are subject to the groundwater monitoring and corrective action requirements under §§ 257.90 through 257.99, except as provided in paragraph (g) of this section.

* * * * *

(g) *Suspension of groundwater monitoring requirements.* (1) The Participating State Director or EPA where EPA is the permitting authority may suspend the groundwater monitoring requirements under §§ 257.90 through 257.95 for a CCR unit for a period of up to ten years, if the owner or operator provides written documentation that, based on the characteristics of the site in which the CCR unit is located, there is no potential for migration of any of the constituents listed in appendices III and IV to this part from that CCR unit to the uppermost aquifer during the active life of the CCR unit and the post-closure care period. This demonstration must be certified by a qualified professional

engineer and approved by the Participating State Director or EPA where EPA is the permitting authority, and must be based upon:

(i) Site-specific field collected measurements, sampling, and analysis of physical, chemical, and biological processes affecting contaminant fate and transport, including at a minimum, the information necessary to evaluate or interpret the effects of the following properties or processes on contaminant fate and transport:

(A) Aquifer Characteristics, including hydraulic conductivity, hydraulic gradient, effective porosity, aquifer thickness, degree of saturation, stratigraphy, degree of fracturing and secondary porosity of soils and bedrock, aquifer heterogeneity, groundwater discharge, and groundwater recharge areas;

(B) Waste Characteristics, including quantity, type, and origin;

(C) Climatic Conditions, including annual precipitation, leachate generation estimates, and effects on leachate quality;

(D) Leachate Characteristics, including leachate composition, solubility, density, the presence of immiscible constituents, Eh, and pH; and

(E) Engineered Controls, including liners, cover systems, and aquifer controls (*e.g.,* lowering the water table). These must be evaluated under design and failure conditions to estimate their long-term residual performance.

(ii) Contaminant fate and transport predictions that maximize contaminant migration and consider impacts on human health and the environment.

(2) The owner or operator of the CCR unit may renew this suspension for additional ten year periods by submitting written documentation that the site characteristics continue to ensure there will be no potential for migration of any of the constituents listed in Appendices III and IV of this part. The documentation must include, at a minimum, the information specified in paragraphs (g)(1)(i) and (g)(1)(ii) of this section and a certification by a qualified professional engineer and approved by the State Director or EPA where EPA is the permitting authority. The owner or operator must submit the documentation supporting their renewal request for the state's or EPA's review and approval of their extension one year before the groundwater monitoring suspension is due to expire. If the existing groundwater monitoring extension expires or is not approved, the owner or operator must begin groundwater monitoring according to paragraph (a) of this section within 90 days. The owner or operator may continue to renew the suspension for ten-year periods, provided the owner or operator demonstrate that the standard in paragraph (g)(1) of this section continues to be met for the unit. The owner or operator must place each completed demonstration in the facility's operating record.

(3) The owner or operator of the CCR unit must include in the annual groundwater monitoring and corrective action report required by § 257.90(e) or § 257.100(e)(5)(ii) any approved no migration demonstration.

■ 15. Section 257.91 is amended by revising paragraph (f) to read as follows:

§ 257.91 Groundwater monitoring systems.

* * * * *

(f) The owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the groundwater monitoring system has been designed and constructed to meet the requirements of this section. If the groundwater monitoring system includes the minimum number of monitoring wells specified in paragraph (c)(1) of this section, the certification must document the basis supporting this determination.

* * * * *

■ 16. Section 257.93 is amended by revising paragraph (f)(6) to read as follows:

§ 257.93 Groundwater sampling and analysis requirements.

* * * * *

(f) * * *

(6) The owner or operator of the CCR unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the selected statistical method is appropriate for evaluating the groundwater monitoring data for the CCR management area. The certification must include a narrative description of the statistical method selected to evaluate the groundwater monitoring data.

* * * * *

■ 17. Section 257.94 is amended by revising paragraphs (d)(3) and (e)(2) to read as follows:

§ 257.94 Detection monitoring program.

* * * * *

(d) * * *

(3) The owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the demonstration for an alternative groundwater sampling and analysis frequency meets the requirements of this section. The owner or operator must include the demonstration providing the basis for the alternative monitoring frequency and the certification by a qualified professional engineer or the approval from the Participating State Director or approval from EPA where EPA is the permitting authority in the annual groundwater monitoring and corrective action report required by § 257.90(e).

(e) * * *

(2) The owner or operator may demonstrate that a source other than the CCR unit caused the statistically significant increase over background levels for a constituent or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality. The owner or operator must complete the written demonstration within 90 days of detecting a statistically significant increase over background levels to include obtaining a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority verifying the accuracy of the information in the report. If a successful demonstration is completed within the 90-day period, the owner or operator of the CCR unit may continue with a detection monitoring program under this section. If a successful demonstration is not completed within the 90-day period, the owner or operator of the CCR unit must initiate an assessment monitoring program as required under § 257.95. The owner or operator must also include the demonstration in the annual groundwater monitoring and corrective action report required by § 257.90(e), in addition to the certification by a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority.

* * * * *

■ 18. Section 257.95 is amended by revising paragraphs (c)(3), (g)(3)(ii), (h)(2) and (3) to read as follows:

§ 257.95 Assessment monitoring program.

* * * * *

(c) * * *

(3) The owner or operator must obtain a certification from a qualified

professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the demonstration for an alternative groundwater sampling and analysis frequency meets the requirements of this section. The owner or operator must include the demonstration providing the basis for the alternative monitoring frequency and the certification by a qualified professional engineer or the approval from the Participating State Director or the approval from EPA where EPA is the permitting authority in the annual groundwater monitoring and corrective action report required by § 257.90(e).

* * * * *

(g) * * *

(3) * * *

(ii) Demonstrate that a source other than the CCR unit caused the contamination, or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality. Any such demonstration must be supported by a report that includes the factual or evidentiary basis for any conclusions and must be certified to be accurate by a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority. If a successful demonstration is made, the owner or operator must continue monitoring in accordance with the assessment monitoring program pursuant to this section, and may return to detection monitoring if the constituents in Appendix III and Appendix IV of this part are at or below background as specified in paragraph (e) of this section. The owner or operator must also include the demonstration in the annual groundwater monitoring and corrective action report required by § 257.90(e), in addition to the certification by a qualified professional engineer or the approval from the Participating State Director or the approval from EPA where EPA is the permitting authority.

* * * * *

(h) * * *

(2) For the following constituents:

(i) Cobalt 6 micrograms per liter (μg/l);

(ii) Lead 15 μg/l;

(iii) Lithium 40 μg/l; and

(iv) Molybdenum 100 μg/l.

(3) For constituents for which the background level is higher than the levels identified under paragraphs (h)(1) and (h)(2) of this section, the background concentration.

* * * * *

■ 19. Section 257.96 is amended by revising paragraph (a) to read as follows:

§ 257.96 Assessment of corrective measures.

(a) Within 90 days of finding that any constituent listed in Appendix IV to this part has been detected at a statistically significant level exceeding the groundwater protection standard defined under § 257.95(h), or immediately upon detection of a release from a CCR unit, the owner or operator must initiate an assessment of corrective measures to prevent further releases, to remediate any releases and to restore affected area to original conditions. The assessment of corrective measures must be completed within 90 days, unless the owner or operator demonstrates the need for additional time to complete the assessment of corrective measures due to site-specific conditions or circumstances. The owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority attesting that the demonstration is accurate. The 90-day deadline to complete the assessment of corrective measures may be extended for no longer than 60 days. The owner or operator must also include the demonstration in the annual groundwater monitoring and corrective action report required by § 257.90(e), in addition to the certification by a qualified professional engineer or the approval from the Participating State Director or the approval from EPA where EPA is the permitting authority.

* * * * *

■ 20. Section 257.97 is amended by revising paragraph (a) to read as follows:

§ 257.97 Selection of remedy.

(a) Based on the results of the corrective measures assessment conducted under § 257.96, the owner or operator must, as soon as feasible, select a remedy that, at a minimum, meets the standards listed in paragraph (b) of this section. This requirement applies in addition to, not in place of, any applicable standards under the Occupational Safety and Health Act. The owner or operator must prepare a semiannual report describing the progress in selecting and designing the remedy. Upon selection of a remedy, the owner or operator must prepare a final report describing the selected remedy and how it meets the standards specified in paragraph (b) of this section. The owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the remedy selected meets the requirements of this section. The report has been completed when it is placed in the operating record as required by § 257.105(h)(12).

* * * * *

■ 21. Section 257.98 is amended by revising paragraph (e) to read as follows:

§ 257.98 Implementation of the corrective action program.

* * * * *

(e) Upon completion of the remedy, the owner or operator must prepare a notification stating that the remedy has been completed. The owner or operator must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority attesting that the remedy has been completed in compliance with the requirements of paragraph (c) of this section. The report has been completed when it is placed in the operating record as required by § 257.105(h)(13).

* * * * *

■ 22. Section 257.101 is amended by revising paragraphs (a)(1) and (b)(1) to read as follows:

§ 257.101 Closure or retrofit of CCR units.

(a) * * *

(1) Except as provided by paragraph (a)(3) of this section, if at any time after October 19, 2015, an owner or operator of an existing unlined CCR surface impoundment determines in any sampling event that the concentrations of one or more constituents listed in appendix IV of this part are detected at statistically significant levels above the groundwater protection standard established under § 257.95(h) for such CCR unit, within six months of making such determination or no later than October 31, 2020, whichever date is later, the owner or operator of the existing unlined CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR surface impoundment and either retrofit or close the CCR unit in accordance with the requirements of § 257.102.

* * * * *

(b) * * *

(1)(i) *Location standard under § 257.60.* Except as provided by paragraph (b)(4) of this section, the owner or operator of an existing CCR surface impoundment that has not demonstrated compliance with the location standard specified in § 257.60(a) must cease placing CCR and non-CCR wastestreams into such CCR

unit no later than October 31, 2020, and close the CCR unit in accordance with the requirements of § 257.102.

(ii) *Location standards under §§ 257.61 through 257.64.* Except as provided by paragraph (b)(4) of this section, within six months of determining that an existing CCR surface impoundment has not demonstrated compliance with any location standard specified in §§ 257.61(a), 257.62(a), 257.63(a), and 257.64(a), the owner or operator of the CCR surface impoundment must cease placing CCR and non-CCR wastestreams into such CCR unit and close the CCR unit in accordance with the requirements of § 257.102.

* * * * *

■ 23. Section 257.102 is amended by revising paragraphs (b)(4), (d)(3)(iii), (f)(3), (g), (h), (k)(2)(iv), (k)(4) and (k)(6) to read as follows:

§ 257.102 Criteria for conducting the closure or retrofit of CCR units.

* * * * *

(b) * * *

(4) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the initial and any amendment of the written closure plan meets the requirements of this section.

* * * * *

(d) * * *

(3) * * *

(iii) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the design of the final cover system meets the requirements of this section.

* * * * *

(f) * * *

(3) Upon completion, the owner or operator of the CCR unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority verifying that closure has been completed in accordance with the closure plan specified in paragraph (b) of this section and the requirements of this section.

(g) No later than the date the owner or operator initiates closure of a CCR unit, the owner or operator must prepare a notification of intent to close a CCR unit. The notification must include the certification by a qualified professional engineer or the approval from the Participating State Director or the approval from EPA where EPA is the permitting authority for the design of the final cover system as required by § 257.102(d)(3)(iii), if applicable. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(7).

(h) Within 30 days of completion of closure of the CCR unit, the owner or operator must prepare a notification of closure of a CCR unit. The notification must include the certification by a qualified professional engineer or the approval from the Participating State Director or the approval from EPA where EPA is the permitting authority as required by § 257.102(f)(3). The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(8).

(k) * * *

(2) * * *

(iv) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer or an approval from the Participating State Director or an approval from EPA where EPA is the permitting authority that the activities outlined in the written retrofit plan, including any amendment of the plan, meet the requirements of this section.

* * * * *

(4) Upon completion, the owner or operator must obtain a written certification from a qualified professional engineer or an approval from the Participating State Director or an approval from EPA where EPA is the permitting authority verifying that the retrofit activities have been completed in accordance with the retrofit plan specified in paragraph (k)(2) of this section and the requirements of this section.

* * * * *

(6) Within 30 days of completing the retrofit activities specified in paragraph (k)(1) of this section, the owner or operator must prepare a notification of completion of retrofit activities. The notification must include the certification from a qualified professional engineer or an approval from the Participating State Director or an approval from EPA where EPA is the permitting authority has is required by paragraph (k)(4) of this section. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(j)(6).

* * * * *

■ 24. Section 257.104 is amended by revising paragraphs (d)(1)(iii), (d)(4) and (e) to read as follows:

§ 257.104 Post-closure care requirements.

* * * * *

(d) * * *

(1) * * *

(iii) A description of the planned uses of the property during the post-closure period. Post-closure use of the property shall not disturb the integrity of the final cover, liner(s), or any other component of the containment system, or the function of the monitoring systems unless necessary to comply with the requirements in this subpart. Any other disturbance is allowed if the owner or operator of the CCR unit demonstrates that disturbance of the final cover, liner, or other component of the containment system, including any removal of CCR, will not increase the potential threat to human health or the environment. The demonstration must be certified by a qualified professional engineer or approved by the Participating State Director or approved from EPA where EPA is the permitting authority, and notification shall be provided to the State Director that the demonstration has been placed in the operating record and on the owners or operator's publicly accessible internet site.

* * * * *

(4) The owner or operator of the CCR unit must obtain a written certification from a qualified professional engineer or an approval from the Participating State Director or an approval from EPA where EPA is the permitting authority that the initial and any amendment of the written post-closure plan meets the requirements of this section.

(e) *Notification of completion of post-closure care period.* No later than 60 days following the completion of the post-closure care period, the owner or operator of the CCR unit must prepare a notification verifying that post-closure care has been completed. The notification must include the certification by a qualified professional engineer or the approval from the Participating State Director or the approval from EPA where EPA is the permitting authority verifying that post-closure care has been completed in accordance with the closure plan specified in paragraph (d) of this section and the requirements of this section. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(13).

* * * * *

■ 25. Section 257.105 is amended by adding paragraph (h)(14) to read as follows:

§ 257.105 Recordkeeping requirements.

* * * * *

(h) * * *

(14) The demonstration, including long-term performance data, supporting the suspension of groundwater monitoring requirements as required by § 257.90(g).

* * * * *

■ 26. Section 257.106 is amended by adding paragraph (h)(11) to read as follows:

§ 257.106 Notification requirements.

* * * * *

(h) * * *

(11) Provide the demonstration supporting the suspension of groundwater monitoring requirements specified under § 257.105(h)(14).

* * * * *

■ 27. Section 257.107 is amended by adding paragraph (h)(11) to read as follows:

§ 257.107 Publicly accessible internet site requirements.

* * * * *

(h) * * *

(11) The demonstration supporting the suspension of groundwater monitoring requirements specified under § 257.105(h)(14).

* * * * *

[FR Doc. 2018–16262 Filed 7–27–18; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

45 CFR Part 153

[CMS–9920–F]

RIN 0938–AT65

Adoption of the Methodology for the HHS-Operated Permanent Risk Adjustment Program Under the Patient Protection and Affordable Care Act for the 2017 Benefit Year

AGENCY: Centers for Medicare & Medicaid Services (CMS), Department of Health and Human Services (HHS).

ACTION: Final rule.

SUMMARY: This final rule adopts the risk adjustment methodology that HHS previously established for the 2017 benefit year. In February 2018, a district court vacated the use of statewide average premium as a basis for the HHS-operated risk adjustment methodology for the 2014, 2015, 2016, 2017, and 2018 benefit years. Accordingly, HHS is issuing this final rule to allow charges to be collected and payments to be made for the 2017 benefit year. We hereby adopt the final rules set out in the publication in the **Federal Register** on March 23, 2012 and the publication in the **Federal Register** on March 8, 2016.

DATES: These provisions of this final rule are effective on July 30, 2018.

FOR FURTHER INFORMATION CONTACT: Abigail Walker, (410) 786–1725; Adam Shaw, (410) 786–1091; Jaya Ghildiyal, (301) 492–5149; or Adrianne Patterson, (410) 786–0686.

SUPPLEMENTARY INFORMATION:

I. Background

A. Legislative and Regulatory Overview

The Patient Protection and Affordable Care Act (Pub. L. 111–148), was enacted on March 23, 2010; the Health Care and Education Reconciliation Act of 2010 (Pub. L. 111–152) was enacted on March 30, 2010. These statutes are collectively referred to as ''PPACA'' in this final rule. Section 1343 of the PPACA established an annual permanent risk adjustment program under which payments are collected from health insurance issuers that enroll relatively low-risk populations, and payments are made to health insurance issuers that enroll relatively higher-risk populations. Consistent with section 1321(c)(1) of the PPACA, the Secretary is responsible for operating the risk adjustment program on behalf of any state that elected not to do so. For the 2017 benefit year, HHS is responsible for operation of the risk adjustment program in all 50 states and the District of Columbia.

HHS sets the risk adjustment methodology that it uses in states that elect not to operate the program in advance of each benefit year through a notice-and-comment rulemaking process with the intention that issuers will be able to rely on the methodology to price their plans appropriately (45 CFR 153.320; 76 FR 41930, 41932 through 41933; 81 FR 94058, 94702 (explaining the importance of setting rules ahead of time and describing comments supporting that practice)).

In the July 15, 2011 **Federal Register** (76 FR 41929), we published a proposed rule outlining the framework for the risk adjustment program. We implemented the risk adjustment program in a final rule, published in the March 23, 2012 **Federal Register** (77 FR 17219) (Premium Stabilization Rule). In the December 7, 2012 **Federal Register** (77 FR 73117), we published a proposed rule outlining the proposed Federally certified risk adjustment methodologies for the 2014 benefit year and other parameters related to the risk adjustment program (proposed 2014 Payment Notice). We published the 2014 Payment Notice final rule in the March 11, 2013 **Federal Register** (78 FR 15409). In the June 19, 2013 **Federal Register** (78 FR 37032), we proposed a modification to the HHS-operated methodology related to community rating states. In the October 30, 2013, **Federal Register** (78 FR 65046), we finalized the proposed modification to the HHS-operated methodology related to community rating states. We published a correcting amendment to the 2014 Payment Notice final rule in the November 6, 2013 **Federal Register** (78 FR 66653) to address how an enrollee's age for the risk score calculation would be determined under the HHS-operated risk adjustment methodology.

In the December 2, 2013 **Federal Register** (78 FR 72321), we published a proposed rule outlining the Federally certified risk adjustment methodologies for the 2015 benefit year and other parameters related to the risk adjustment program (proposed 2015 Payment Notice). We published the 2015 Payment Notice final rule in the March 11, 2014 **Federal Register** (79 FR 13743). In the May 27, 2014 **Federal Register** (79 FR 30240), the 2015 fiscal year sequestration rate for the risk adjustment program was announced.

In the November 26, 2014 **Federal Register** (79 FR 70673), we published a proposed rule outlining the proposed Federally certified risk adjustment methodologies for the 2016 benefit year and other parameters related to the risk adjustment program (proposed 2016 Payment Notice). We published the 2016 Payment Notice final rule in the February 27, 2015 **Federal Register** (80 FR 10749).

In the December 2, 2015 **Federal Register** (80 FR 75487), we published a proposed rule outlining the Federally certified risk adjustment methodology for the 2017 benefit year and other parameters related to the risk adjustment program (proposed 2017 Payment Notice). We published the 2017 Payment Notice final rule in the March 8, 2016 **Federal Register** (81 FR 12204).

In the September 6, 2016 **Federal Register** (81 FR 61455), we published a proposed rule outlining the Federally certified risk adjustment methodology for the 2018 benefit year and other parameters related to the risk adjustment program (proposed 2018 Payment Notice). We published the 2018 Payment Notice final rule in the December 22, 2016 **Federal Register** (81 FR 94058).

BEFORE THE MISSISSIPPI PUBLIC SERVICE COMMISSION

MISSISSIPPI POWER COMPANY
EC-120-00097-00

DOCKET NO. 2019-UA-116

IN RE: **PETITION OF MISSISSIPPI POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ENVIRONMENTAL COMPLIANCE ACTIVITIES AUTHORIZING THE CLOSURE OF THE ASH POND, CONSTRUCTION OF LOW VOLUME WASTEWATER TREATMENT FACILITIES, AND CONVERSION OF BOTTOM ASH COLLECTION FACILITIES FOR THE PLANT VICTOR J. DANIEL ELECTRIC GENERATING FACILITY IN JACKSON COUNTY, MISSISSIPPI**

ORDER APPROVING PETITION FOR FACILITY CERTIFICATE

THIS CAUSE came on for consideration by the Mississippi Public Service Commission ("Commission") on the request of Mississippi Power Company (the "Company" or "MPCo") for a certificate that the present and future public convenience and necessity requires or will require the closure of the ash pond, construction of a low-volume wastewater facility, and conversion of bottom ash collection facilities (collectively, the "CCR Projects") to ensure continued compliance with federal environmental requirements at the Plant Victor J. Daniel Electric Generating Facility in Jackson County, Mississippi ("Plant Daniel"), pursuant to Sections 77-3-11 and 77-3-13 of the *Mississippi Code of 1972, as amended,* and Rule 7 of this Commission's Public Utilities Rules of Practice and Procedure ("Rules"). This Commission, being fully apprised in the premises, having considered the documents and record before it, and upon recommendation of the Mississippi Public Utilities Staff ("Staff"), finds that the certificate of public convenience and necessity requested by the Company should be granted, and further finds as follows:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 20
PARTY: MWS-2 (20)
DESCRIPTION: Mississippi PSC Order dated October 28, 2019

**MSPSC Electronic Copy ** 2019-UA-116 Filed on 10/28/2019 **

INTRODUCTION

1. The coal units at Plant Daniel ("Units 1 and 2") were placed in service in 1977 and 1981, respectively, and are the newest coal units in MPCo's fleet, which are capable of generating approximately 1,020 MW (net summer peak) of electricity.[1] For MPCo, Units 1 and 2 represent the only significant source of fuel diversity remaining in its fleet following the conversion of all their other coal units to natural gas.

2. To support its units, Plant Daniel employs approximately 200 full-time employees on site in Escatawpa, a small, rural community in Jackson County, Mississippi. A significant majority of these jobs directly support the two (2) coal units, and the Plant, in total, contributes over $18 million annually to the ad valorem tax collections of Jackson County. Units 1 and 2 each have projected remaining useful lives of over 20 years.

3. Over the course of its service, Plant Daniel, and more particularly Units 1 and 2, has been impacted by the policies of the federal Environmental Protection Agency. For example, the Commission approved in 2012 the construction of a flue gas desulphurization system ("Scrubber") to further the continued operation of Units 1 and 2, which was necessitated by federal regulation and represented over $600 million in construction costs. Advancing federal regulations and accommodation of their constrained compliance periods, once again, requires timely action by the Commission.

4. Accordingly, the Commission finds that the Company's petition should be granted for the following reasons and considerations, which will be set forth further in this Order: 1) the proposed projects are required to timely comply with applicable environmental laws respecting ash pond

[1] Plant Daniel is also home to two (2) natural gas-fired combined cycle units (Units 3 and 4) that combined are capable of generating approximately 1,054 MW (net summer peak) of electricity. This Commission also acknowledges that Gulf Power Company (NextEra) owns a 50% undivided interest in Units 1 and 2.

**MSPSC Electronic Copy ** 2019-UA-116 Filed on 10/28/2019 **

closures and coal combustion residuals (CCR); 2) the transmission constraints identified by MPCo create untenable reliability risks to other compliance alternatives; 3) Units 1 and 2 at Plant Daniel have significant remaining useful life and are not scheduled to retire until 2042 and 2046, respectively;[2] 4) this Commission has previously determined in 2012 when it approved the installation of Scrubber equipment for Units 1 and 2 that preserving coal-fired generation at Plant Daniel provides important fuel diversity and is in the overall best interest of customers;[3] and 5) the Commission, the Public Utilities Staff and the Company have been diligently and deliberately engaging, for over a year, in economic analysis regarding MPCo's fleet of generating assets in the Commission's Reserve Margin Plan Docket,[4] where it is most appropriate for this Commission's policies regarding MPCo's existing generating facilities, including Plant Daniel Units 1 and 2, to be addressed.

PROCEDURAL BACKGROUND

5. The Company filed its Petition for Facility Certificate in this docket on July 9, 2019, and noted both in its filing and in accompanying pre-filed testimony the need for the Commission to move quickly to approve the Petition so that MPCo could comply with federal regulatory deadlines. Specifically, MPCo identified November 1, 2019, as the time by which Commission action would be necessary.

6. Notice of the matter was given to all persons interested therein in accordance with Mississippi law by mailing such notice to each public utility which may be affected, as well as by publication on July 20, 2019, in the Clarion Ledger, a newspaper of general circulation in Jackson, Mississippi, by publication on July 19, 2019, in the Mississippi Press, a newspaper

[2] *In re: Mississippi Power Company*, MPSC Docket No. 2014-UN-0276.
[3] *In re: Mississippi Power Company*, MPSC Docket No. 2010-UA-0279.
[4] MPSC Docket No. 2018-AD-0145.

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of general circulation in Jackson County, Mississippi, and by publication on July 18, 2019, in the Sun-Herald, a newspaper of general circulation in Harrison County, Mississippi.

7. Cooperative Energy and the Sierra Club requested and were granted status as intervenors in this docket.

8. On September 13, 2019, the Commission entered its Scheduling Order, specifically noting the time-sensitive nature of the proceedings and finding that the procedure outlined for submissions would promote efficient administration of the proceedings and would be in the best interest of the public and the interested parties. The Scheduling Order also indicated that at the time of issuance no party had submitted pre-filed testimony and only the Staff had completed its data request exchange with the Company. Moreover, at the time the Commission issued the Scheduling Order, no party had contested or otherwise objected to any matter related to the Petition.

9. The Staff conducted a thorough investigation of MPCo's application and submitted numerous data requests to MPCo to which the Company timely and thoroughly responded.

10. The Commission takes notice that while Sierra Club timely intervened, it waited until September 12, 2019, to issue its data requests to MPCo, over two (2) months after the Company filed its petition in this docket and on the eve of this Commission's Scheduling Order. On September 23, 2019, Sierra Club also filed a Motion to Require Supplementation of the Petition and a Revised Scheduling Order, which MPCo opposed. The parties presented oral argument on such Motion on October 24, 2019, and this Commission hereby confirms its denial of Sierra Club's Motion as provided for in this Order.

11. In addition, Sierra Club provided comments on MPCo's Proposed Order in the form of a report from Synapse Energy Economics, Inc. ("Synapse"). Finally, on October 16, 2019, Sierra

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Club submitted pre-filed direct testimony of Ms. Rachel Wilson of Synapse. MPCo opposed such filing as being out of time and in violation of scheduling order. The Commission agreed and granted MPCo's Motion to Strike Ms. Wilson's testimony. In both its offered comments and offered testimony, Sierra Club requested a delay of this proceeding similar to the request in Sierra Club's initial motion. Sierra Club's lack of prompt engagement in this proceeding should not delay the Commission's timely resolution of this matter, particularly in light of the Company's need to begin ash pond closure activities in November in order to cease receiving non-CCR waste streams by October 31, 2020, as required by the EPA.

12. On October 4, 2019, the Commission noticed the hearing of this matter and on October 24, 2019, the Commission held the hearing where the witness for MPCo appeared, testified, and was tendered for cross-examination by the parties, the Staff, and the Commission. As part of its case in chief, MPCo offered into evidence the public and confidential responses to Staff's and Sierra Club's data requests, and the Commission hereby incorporates MPCo's responses to all data requests by reference into the record in this proceeding and attaches to this Order the non-confidential versions of same.

13. This Commission has jurisdiction over the parties and subject matter pursuant to Sections 77-3-11 and 77-3-13 of the Mississippi Code of 1972, as amended. Given the considerations above, the Commission further finds that the Scheduling Order and hearing provide sufficient process, and the Commission has had opportunity to hear the positions of the parties through the submissions received and the testimony and evidence presented.

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LAW AND EVIDENCE

14. The federal environmental regulations governing CCR at Plant Daniel are similar to the regulations that required the closure of the ash pond facilities at the Company's Plant Jack Watson Electric Generating Plant authorized by this Commission in Docket No. 2016-UA-020. As stated *supra,* the EPA's CCR rules regulate CCR and non-CCR waste streams and require that MPCo cease placing CCR and non-CCR waste streams into the Plant Daniel ash pond by October 31, 2020, followed by closure of the ash pond, which must occur within five (5) years following the commencement of closure activities. Unless the Company commits to the permanent cessation of coal operations at Plant Daniel under the alternative closure requirements of the CCR Rules,[5] the Company must cease placing CCR waste streams into the Plant Daniel ash pond by the October 31, 2020, deadline established by the EPA. However, under all circumstances, the Company must cease placing non-CCR waste streams (e.g. low volume waste water) into the ash pond by that October

31, 2020 deadline.

15. Sierra Club contends in its comments that MPCo did not adequately consider early retirement for Units 1 and 2 as a compliance alternative.[6] Sierra Club suggests that early retirement would allow a delay of the ash pond closure until 2023 and avoid the bottom ash conversion project costs. MPCo, however, contends that early retirement would also require the acceleration of several other closure obligations, including asset retirement obligations, and additional non-CCR waste stream treatment expenses by October 31, 2020, while also creating transmission reliability

[5] 40 C.F.R. §257.103.
[6] *Id.*

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concerns.[7] Sierra Club correctly points out that MPCo's co-owner, Gulf Power Company, has already indicated its intent to retire its ownership interest in Plant Daniel by 2024.

16. In response to data requests, MPCo demonstrated that it would need to finalize several transmission improvements and new projects no later than July 1, 2022 in order to reliably support consideration of early retirement as a technical possibility.[8] While it might theoretically be possible to develop a planned schedule to accommodate outages and complete the transmission projects by July 1, 2022, there are many potential circumstances that could result in an unavoidable delay of the transmission projects, resulting in an unacceptable reliability risk. Events that have the potential to cause delays in schedules cannot be predicted and create uncertainty in the ability to execute a stringent schedule. What can be predicted with certainty is that if: 1) MPCo were to pursue an alternative to cease operation of Plant Daniel on July 1, 2022, so that closure of its impoundment can be completed by the required October 17, 2023, deadline, and 2) the transmission projects were not able to be completed by the July 1, 2022, Plant Daniel shut-down, reliability risk in the region would be unacceptable given that Plant Daniel would not be available for operation nor would the transmission projects be complete.

17. MPCo submits that the transmission constraints foreclose early retirement as a feasible option at this time, regardless of Gulf Power Company's desire to retire its ownership portion, because such constraints would need to be resolved prior to such retirement in 2024. We agree.

18. This Commission finds based upon the evidence in the record that such transmission constraints create an untenable reliability risk to early retirement of Plant Daniel and we are not convinced that the potential capital cost savings of $12.5 million[9] for MPCo is worth that reliability

[7] MPCo Data Request Responses MPUS 1-8, MPUS 1-8 SUPP., MPUS 1-9, MPUS 1-9 SUPP, MPUS 1-13, and MPUS 1-13 SUPP.
[8] *Id.*
[9] *Id.*

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risk, particularly within the narrow timeframes for compliance established by the EPA. We reiterate that the long-term viability of MPCo's generating fleet, including Plant Daniel Units 1 and 2, as well as the impact of Gulf Power Company's intended retirement, are being considered in the RMP Docket; therefore, we find that the CCR Projects as proposed by MPC provide the most prudent path to compliance with the CCR Rules at this time and under these circumstances.

19. To comply with the EPA's regulations, MPCo must rapidly complete each of the following components of the CCR Projects, and must do so sequentially: 1) MPCo must complete a conversion of the bottom ash collection system that will not require use of the ash pond for the discharge of any CCR waste stream; 2) following the bottom ash conversion, the ash pond itself must be closed by first ceasing receipt of any CCR or non-CCR and then by removing all CCR in accordance with 40 C.F.R. § 257.102(c); and 3) following the ash pond closure, a new low-volume wastewater treatment system must be constructed on the site of the former ash pond. No party has presented evidence in this proceeding that is contrary to both the specific requirements and timing of compliance activities proposed by MPCo.

20. Time is of the essence. To comply with EPA's timeline, MPCo must begin construction of the CCR Projects no later than November 1, 2019. The total cost for all of the work described herein is approximately $125 million. As an undivided owner of 50% of Plant Daniel Units 1 and 2, MPC's portion of the project costs would be approximately $62.5 million.[10]

21. As explained in the testimony of Mr. Mark Loughman, MPCo's Director of Environmental Affairs, Plant Daniel's existing Ash Pond must be closed in order to comply with the CCR Rule under Subtitle D of the Resource Conservation and Recovery Act. 40 CFR § 257.60(a) and §

[10] In data response MPUS 1-21 (Attachment), MPCo indicated that the estimate may be closer to $67 million because a small portion of the CCR Project is necessary to support Plant Daniel Unit 3 and Unit 4, which are wholly owned by MPCo.

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257.101(b)(1). Its closure is governed by 40 CFR § 257.102(c), which requires the removal of all CCR from the ash pond and closure of the ash pond within five (5) years of commencing closure activities. More importantly, MPCo must cease placing CCR *and* non-CCR waste streams into the ash pond no later than October 31, 2020. MPCo currently expects to complete ash pond closure activities at Plant Daniel by the first quarter of 2022. Time is of the essence of these CCR Projects.

22. As Mr. Loughman describes in his testimony, the ash pond currently serves the dual purposes of bottom ash storage and low volume wastewater (LVW) retention of both CCR and non-CCR waste streams. Because the CCR Rule requires MPCo to cease receiving both types of waste streams into the ash pond by October 31, 2020, alternate facilities are required by that deadline to accommodate such waste streams once they can no longer be placed into the ash pond.

23. To that end, the Company plans to close the ash pond as described above in compliance with the applicable laws governing such closures, and to repurpose the former ash pond impoundment to serve as a LVW retention pond as described in Mr. Loughman's testimony. With respect to the bottom ash created by the coal combustion process that is currently sluiced to the ash pond, the Company plans to install a Submerged Grind Conveyor (SGC) system. A second SGC will de-water the bottom ash and transport it to a bunker for storage in compliance with applicable environmental laws and regulations.

24. While Mr. Loughman's testimony is uncontroverted in the record, additional considerations warrant attention. As noted previously, Plant Daniel, particularly its coal units, contribute substantially to the economic well-being of Jackson County. Moreover, that contribution is projected, at least, to continue for another 20 years: Based upon the last depreciation study filed by the Company and approved by this Commission in Docket No. 2014-UN-0276, Plant Daniel Units 1 and 2 have projected retirement dates of 2042 and 2046, respectively.

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25. Beyond the local economic contribution, coal-fired generation is MPCo's predominant source of fuel diversity, a policy this Commission has repeatedly observed. Just this past October, the Commission submitted comments in support of the Affordable Clean Energy rule, which confirmed its earlier opposition to the Clean Power Plan. The Commission's comments noted the following regarding the preservation of coal-fired generation in Mississippi: "Because Mississippi's climate and geography limit the potential for extensive investments in renewable sources, preserving some coal-fired generation is currently critical for maintaining fuel diversity and rate stability."[11] In 2014, the Commission submitted comments in opposition to the Clean Power Plan, again noting the need for fuel diversity and highlighting the detrimental effects of eliminating coal-fired generating resources.[12]

26. Consistent in its approach, in Docket No. 2010-UA-0279, the Commission approved MPCo's construction of a Scrubber for Plant Daniel Units 1 and 2, which preserved MPCo's currently scheduled unit retirement dates. In its order in the Scrubber docket, the Commission indicated its preference for fuel diversity and for the continued operating of coal-fired generation in MPCo's fleet where it stated: "[t]he Commission finds the strategic interest of fuel diversity very compelling and gives significant weight to this consideration."[13] In that Order, the Commission further explained its rationale for maintaining some fuel diversity by continuing to support the operation of some coal-fired generation at Plant Daniel:

> The Commission places superior weight on the benefits of fuel diversity and fuel security offered by the Scrubber Project and finds that these benefits to MPCo's ratepayers conclusively place the Scrubber Project ahead of a combined cycle alternative. Stated differently, the Commission finds that, given the "inconclusive"

[11] MPSC Comments submitted in Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program; Proposed Rule, Docket No. EPA-HQ-OAR-2017-0355 (October 30, 2018).
[12] See pp. 18-20 of comments of MPSC in *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule*, Docket No. EPA-HQ-OAR-2013-0602 (2014).
[13] *In re: Petition of Mississippi Power Company*, Order, pg. 12, MPSC Docket No. 2010-UA-0279 (2012).

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> or neutral economics noted by Drs. Vatter and Van Vactor, the strategic benefits of the Scrubber Project make it the best choice to serve the public interest and thereby satisfies the public convenience and necessity.[14]

27. Without Plant Daniel Units 1 and 2, MPCo's owned generating capacity would be 100% dependent upon natural gas, which this Commission believes is not in the best interest of MPCo's customers at this time.[15]

28. As with the Scrubber matter, the Commission may once again face neutral or non-determinative economic analysis, in which Commission policy considerations and choices will come to the fore. Those deliberations and decisions, however, are best addressed in the Commission's Reserve Margin Plan Docket, since it was established for that purpose.

29. For example, some data requests and responses indicate that if the Commission ordered early retirement of Unit 1 and Unit 2, then approximately $45 million of CCR Project related costs could be avoided. However, because early retirement would accelerate other asset retirement obligations and related closure costs, the savings realized would be closer to $25 million, which represents approximately $12.5 million to MPCo based upon ownership percentage. Assuming those costs could actually be avoided and that the transmission construction schedule risk would be worth taking, MPCo's portion of those savings is relatively small compared to the overall investment at Plant Daniel and is certainly less significant than the weightier decision of whether to retire two units twenty years ahead of schedule that would largely eliminate MPCo's existing fuel diversity.

30. The Staff and its consultants have been diligently working with the Company in the Reserve Margin Docket to present a full picture to this Commission so that it may make the best

[14] *Id.* at 15.
[15] MPCo has approximately 150 megawatts of renewable energy under long-term output power purchase agreements on an energy-only basis (i.e. MPCo does not own the facilities).

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decision possible on a prudent timetable. This Commission finds that an economic re-analysis of Plant Daniel Unit 1 and Unit 2 does not serve the public interest, at this time. To the extent any additional economic analysis regarding MPCo's fleet of generating assets is performed in the Commission's Reserve Margin Docket established in Docket No. 2018-AD-0145, those results and any impacts on this Commission's policies regarding MPCo's existing generating facilities, including Plant Daniel Unit 1 and Unit 2, will be addressed in that proceeding.

CONCLUSION

31. For all the foregoing reasons and for all the reasons set forth in this Order, the Commission hereby finds that the public convenience and necessity requires and will require the CCR Projects proposed in the Company's petition to preserve the continued operation of its only coal-fired generation available for service to customers in Southeast Mississippi. However, acknowledging the ongoing review of MPCo's existing generation facilities in a distinct proceeding – the Reserve Margin Plan Docket – and that differing policy arguments continue to exist surrounding the continued operation of coal-fired generation facilities, generally, the Commission notes that the current deadlines established by the EPA motivate the granting of the instant petition. The granting of this petition does not suggest that the Commission is reaching, or has reached, a conclusion as to the continued operation of Plant Daniel in the Reserve Margin Plan Docket. Moreover, this Order in no way precludes future Commissions from revisiting the question of how to manage the public interest and necessity when considering fuel diversity needs in the future, especially as such diversity relates to the continued operation of coal-fired generation units.

32. The Company has reasonably complied with the applicable filing requirements and has provided information sufficient for the Commission's and the Staffs consideration of this matter.

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Therefore, for good cause shown, this Commission waives any other filing requirements as prescribed by this Commission's Rules and not provided by the Company.

33. While this Commission finds that the public convenience and necessity require the CCR Projects, we are sensitive to the positions espoused by Sierra Club in this proceeding regarding the continued review of the long-term viability of Plant Daniel Units 1 and 2, and this Commission's need to carefully consider the potential retirement of those units in the Reserve Margin Plan Docket. To that end, this Commission believes certain safeguards for customers are appropriate as set forth below.

WHEREFORE PREMISES CONSIDERED, it is therefore,

ORDERED, and the Commission hereby finds that the public convenience and necessity requires the CCR Projects as proposed and hereby grants the Company a Certificate of Public Convenience and Necessity authorizing the Company to perform the CCR Projects as described above and in the Company's Petition. It is further,

ORDERED, that as a continuing condition of this Order and the granting of a certificate hereunder, MPCo shall submit monthly reports to the Staff and Commission on the expenditures of the CCR Projects including the cumulative costs incurred to date, the estimated total costs to complete, the estimated total costs to cancel the project and the remaining contingency allowance. It is further,

ORDERED, that MPCo shall file updated analysis in the Reserve Margin Plan, Docket No. 2018-AD-0145, by December 31, 2019. It is further,

ORDERED, and the Commission affirmatively declares that no portion of the costs associated with the CCR Projects that are contractually assigned to Gulf Power Company shall be recoverable by MPCo in its rates. It is further,

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ORDERED, that if, upon the conclusion of the Reserve Margin Plan Docket, the Commission determines that the early retirement of Plant Daniel Units 1 and 2 serves the public interest and that the CCR Projects no longer serve the public interest, MPCo will use commercially reasonable efforts to safely and promptly cease those efforts, and any dollars committed to said CCR Projects after the date of such an Order will not be recoverable by MPCo in its rates. It is further,

ORDERED, that Sierra Club is hereby granted late intervenor status in the Reserve Margin Plan Docket, No. 2018-AD-0145, to participate fully as a party in said docket including the right to issue data requests and to file testimony within any deadlines prescribed by the Commission, and the Executive Secretary is directed to enter and Order to such effect. It is further,

ORDERED, that Sierra Club's Motion to Require Supplementation of the Petition and a Revised Scheduling Order is not well-taken, and is denied. It is further,

ORDERED, that MPCo's Motion to Strike Testimony regarding the late-filed testimony of Rachel Wilson is well-taken, and is granted, and that the testimony of David Schmitt that MPCo filed in rebuttal to Ms. Wilson's testimony is also stricken.

This Order shall be deemed issued on the day it is served upon the parties herein by the Executive Secretary of this Commission who shall note the service date in the file of this Docket.

Commission Vote

Chairman Brandon Presley	Aye ✓	Nay _____
Vice Chairman Cecil Brown	Aye ✓	Nay _____
Commissioner Samuel F. Britton	Aye ✓	Nay _____

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SO ORDERED by this Commission on this the 28th day of October, 2019.

MISSISSIPPI PUBLIC SERVICE COMMISSION

BRANDON PRESLEY, CHAIRMAN

CECIL BROWN, VICE-CHAIRMAN

SAM BRITTON, COMMISSION

ATTEST: A True Copy

Katherine Collier
Executive Secretary

Effective this the 28th day of October, 2019

MISSISSIPPI PUBLIC SERVICE COMMISSION

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DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Commission Forms 42-1A Through 42-9A

January 2019 - December 2019
Final True-Up
Docket No. 20200007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 21
PARTY: CAM-1
DESCRIPTION: Forms 42-1A - 42-9A January 2019 – December 2019

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019
(in Dollars)

Form 42-1A

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)

Line		Period Amount
1	Over/(Under) Recovery for the Period January 2019 - December 2019 (Form 42-2A, Line 5 + 6 + 10)	$ 14,873,567
2	Actual/Estimated True-Up Amount Approved for the Period January 2019 - December 2019 (Order No. PSC-2019-0500-FOF-EI)	16,666,006
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2020 to December 2020 (Lines 1 - 2)	$ (1,792,439)

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$3,815,052	$3,854,689	$3,938,619	$4,104,582	$4,513,384	$5,409,150	$5,326,315	$5,491,091	$5,601,793	$4,928,636	$4,684,231	$3,749,298	55,416,840
2	True-Up Provision (Order No. PSC-2018-0014-FOF-EI)	9,258,985	$771,582	$771,582	$771,582	$771,582	$771,582	$771,582	$771,582	$771,582	$771,582	$771,582	$771,582	$771,582	9,258,985
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		$4,586,634	4,626,271	4,710,201	4,876,164	5,284,966	6,180,732	6,097,897	6,262,673	6,373,375	5,700,219	5,455,813	4,520,880	64,675,825
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		$1,866,306	$1,405,024	$3,060,780	$2,621,982	$1,945,487	$2,012,831	$2,491,478	$2,139,881	$2,025,824	$2,699,036	$2,240,418	$393,140	$24,902,187
	b. Capital Investment Projects (Form 42-7A, Line 9)		2,074,662	2,184,102	2,182,832	2,138,380	2,117,545	2,058,260	2,056,544	2,063,745	2,030,513	2,026,328	2,106,891	2,122,746	25,162,548
	c. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Total Jurisdictional ECRC Costs		$3,940,968	$3,589,126	$5,243,612	$4,760,362	$4,063,032	$4,071,091	$4,548,022	$4,203,626	$4,056,337	$4,725,364	$4,347,309	$2,515,886	$50,064,735
5	Over/(Under) Recovery (Line 3 - Line 4d)		$645,666	$1,037,145	($533,410)	$115,802	$1,221,934	$2,109,641	$1,549,875	$2,059,047	$2,317,038	$974,854	$1,108,504	$2,004,994	$14,611,090
6	Interest Provision (Form 42-3A, Line 10)		22,482	22,667	21,992	20,135	19,576	20,880	21,587	22,121	23,898	22,836	21,429	22,874	262,477
7	Beginning Balance True-Up & Interest Provision		9,258,985	9,155,551	9,443,781	8,160,780	7,525,135	7,995,062	9,354,001	10,153,881	11,463,467	13,032,822	13,258,930	13,617,281	9,258,985
	a. Deferred True-Up - January 2018 - December 2018 (2018 TU filing dated 3/29/19)		1,988,942	1,988,942	1,988,942	1,988,942	1,988,942	1,988,942	1,988,942	1,988,942	1,988,942	1,988,942	1,988,942	1,988,942	1,988,942
8	True-Up Collected/(Refunded) (see Line 2)		(771,582)	(771,582)	(771,582)	(771,582)	(771,582)	(771,582)	(771,582)	(771,582)	(771,582)	(771,582)	(771,582)	(771,582)	(9,258,985)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		$11,144,493	$11,432,723	$10,149,722	$9,514,077	$9,984,004	$11,342,943	$12,142,823	$13,452,409	$15,021,764	$15,247,872	$15,606,223	$16,862,509	$16,862,509
10	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up Over/(Under) (Lines 9 + 10)		$11,144,493	$11,432,723	$10,149,722	$9,514,077	$9,984,004	$11,342,943	12,142,823	$13,452,409	$15,021,764	$15,247,872	$15,606,223	$16,862,509	$16,862,509

Notes:
(A) N/A

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Interest Provision
(in Dollars)

Line	Description	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$11,247,927	$11,144,493	$11,432,723	$10,149,722	$9,514,077	$9,984,004	$11,342,943	$12,142,823	$13,452,409	$15,021,764	$15,247,872	$15,606,223	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	11,122,011	11,410,056	10,127,730	9,493,942	9,964,428	11,322,063	12,121,236	13,430,288	14,997,866	15,225,036	15,584,794	16,839,635	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	22,369,938	22,554,549	21,560,453	19,643,664	19,478,505	21,306,068	23,464,179	25,573,111	28,450,275	30,246,800	30,832,666	32,445,858	
4	Average True-Up Amount (Line 3 x 1/2)	11,184,969	11,277,275	10,780,227	9,821,832	9,739,253	10,653,034	11,732,090	12,786,556	14,225,138	15,123,400	15,416,333	16,222,929	
5	Interest Rate (Last Business Day of Prior Month)	2.42%	2.41%	2.41%	2.48%	2.43%	2.39%	2.32%	2.10%	2.05%	1.97%	1.66%	1.67%	
6	Interest Rate (Last Business Day of Current Month)	2.41%	2.41%	2.48%	2.43%	2.39%	2.32%	2.10%	2.05%	1.97%	1.66%	1.67%	1.71%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	4.83%	4.82%	4.89%	4.91%	4.82%	4.71%	4.42%	4.15%	4.02%	3.63%	3.33%	3.38%	
8	Average Interest Rate (Line 7 x 1/2)	2.415%	2.410%	2.445%	2.455%	2.410%	2.355%	2.210%	2.075%	2.010%	1.815%	1.665%	1.690%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.201%	0.201%	0.204%	0.205%	0.201%	0.196%	0.184%	0.173%	0.168%	0.151%	0.139%	0.141%	
10	Interest Provision for the Month (Line 4 x Line 9)	$22,482	$22,667	$21,992	$20,135	$19,576	$20,880	$21,587	$22,121	$23,898	$22,836	$21,429	$22,874	$262,477

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Variance Report of O&M Activities
(In Dollars)

Line		(1) YTD Actual	(2) Actual/ Estimated	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities - System				
1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$732,080	$618,709	$113,372	18%
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	17,585	12,053	5,532	46%
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	9,961	7,500	2,461	33%
3	Pipeline Integrity Management - Bartow /Anclote Pipeline - Intm	0	0	0	0%
4	Above Ground Tank Secondary Containment	0	0	0	0%
5	SO2/NOx Emissions Allowances - Energy	10,341	16,059	(5,718)	-36%
6	Phase II Cooling Water Intake 316(b) - Base	394,107	326,355	67,753	21%
6a	Phase II Cooling Water Intake 316(b) - Intm	421,400	390,922	30,479	8%
7.2	CAIR/CAMR - Peaking - Demand	0	0	0	0%
7.4	CAIR/CAMR Crystal River - Base	13,780,599	14,706,826	(926,227)	-6%
7.4	CAIR/CAMR Crystal River - Energy	7,922,177	8,070,700	(148,523)	-2%
7.4	CAIR/CAMR Crystal River - A&G	79,844	88,186	(8,343)	-9%
7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	1,484,028	924,619	559,410	61%
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0%
8	Arsenic Groundwater Standard - Base	99,915	150,000	(50,085)	-33%
9	Sea Turtle - Coastal Street Lighting - Distrib	(47,974)	(47,974)	0	0%
11	Modular Cooling Towers - Base	0	0	0	0%
12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0%
13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0%
14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0%
15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0%
15.1	Effluent Limitation Guidelines Program CRN - Energy	0	0	0	0%
16	National Pollutant Discharge Elimination System (NPDES) - Energy	29,903	26,374	3,529	13%
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	9,213	162,841	(153,628)	-94%
17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0%
17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	45,152	45,152	0	0%
18	Coal Combustion Residual (CCR) Rule - Energy	2,124,816	2,022,617	102,200	5%
2	Total O&M Activities - Recoverable Costs	$27,113,148	$27,520,938	($407,790)	-1%
3	Recoverable Costs Allocated to Energy	11,625,630	11,268,361	357,269	3%
4	Recoverable Costs Allocated to Demand	15,487,518	16,252,577	(765,059)	-5%

Notes:
Column (1) End of Period Totals on Form 42-5A
Column (2) 2019 Estimated/Actual Filing (7/26/2019)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

O&M Activities
(in Dollars)

Line		Description	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1		Description of O&M Activities													
	1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$15,946	$158,436	$250,680	$41,115	$118,533	$9,507	$35,528	$41,769	$35,714	$18,632	$0	$6,221	$732,080
	1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	(7,714)	2,536	10,402	2,262	2,412	2,156	2,336	27,176	(23,982)	0	0	0	17,585
	2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0	0	6,755	0	3,206	0	0	0	0	9,961
	3	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	Above Ground Tank Secondary Containment - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	SO2/NOx Emissions Allowances - Energy	1,965	729	0	(3,148)	914	1,046	1,254	1,396	1,132	1,409	1,964	1,680	10,341
	6	Phase II Cooling Water Intake 316(b) - Base	13,731	28,160	26,572	23,280	2,724	47,199	65,077	0	42,297	0	0	145,067	394,107
	6a	Phase II Cooling Water Intake 316(b) - Intm	3,372	46,388	0	24,895	103,742	(47,199)	68,684	32,999	(901)	0	0	189,419	421,400
	7.2	CAIR/CAMR - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River - Base	1,204,590	1,302,839	2,257,606	1,719,390	960,939	939,462	1,011,291	1,308,667	989,425	1,327,882	781,710	(23,203)	13,780,599
	7.4	CAIR/CAMR Crystal River - Energy	505,618	68,407	573,674	535,668	499,090	771,638	1,212,902	570,733	874,553	1,243,435	1,071,896	(5,436)	7,922,177
	7.4	CAIR/CAMR Crystal River - A&G	6,860	7,229	8,724	7,013	7,034	7,233	7,876	7,122	5,193	4,912	5,753	4,895	79,844
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	0	64,404	11,738	78,832	76,671	92,974	222,128	158,183	169,308	255,614	301,089	53,088	1,484,028
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	8	Arsenic Groundwater Standard - Base	0	13,525	35,032	4,949	5,029	13,359	7,638	2,184	8,026	2,462	4,503	3,209	99,915
	9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0	0	0	(47,974)	0	0	0	0	0	(47,974)
	11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15.1	Effluent Limitation Guidelines ICR Program CRN - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	0	0	0	2,135	3,339	0	0	16,323	8,105	0	0	0	29,903
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	0	0	0	1,841	0	0	7,372	0	0	0	0	0	9,213
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	(12)	0	0	45,164	0	0	0	0	0	0	0	0	45,152
	18	Coal Combustion Residual (CCR) Rule - Energy	245,538	(131,514)	159,158	326,069	354,854	361,379	156,497	169,566	107,029	100,346	190,900	84,994	2,124,816
2		Total of O&M Activities	$1,989,895	$1,561,138	$3,333,586	$2,809,463	$2,135,282	$2,205,509	$2,750,608	$2,339,326	$2,215,900	$2,954,692	$2,357,815	$459,934	$27,113,148
3		Recoverable Costs Allocated to Energy	753,109	2,026	744,570	986,560	934,868	1,227,037	1,600,152	916,202	1,160,128	1,600,804	1,565,849	134,326	11,625,630
4		Recoverable Costs Allocated to Demand - Transm	15,946	158,436	250,680	41,115	118,533	9,507	35,528	41,769	35,714	18,632	0	6,221	732,080
		Recoverable Costs Allocated to Demand - Distrib	(7,714)	2,536	10,402	2,262	2,412	8,911	(45,637)	30,383	(23,982)	0	0	0	(20,428)
		Recoverable Costs Allocated to Demand - Prod-Base	1,218,321	1,344,524	2,319,210	1,747,618	968,693	1,000,020	1,084,005	1,310,851	1,039,748	1,330,344	786,213	125,073	14,274,621
		Recoverable Costs Allocated to Demand - Prod-Intm	3,372	46,388	0	24,895	103,742	(47,199)	68,684	32,999	(901)	0	0	189,419	421,400
		Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
		Recoverable Costs Allocated to Demand - A&G	6,860	7,229	8,724	7,013	7,034	7,233	7,876	7,122	5,193	4,912	5,753	4,895	79,844
5		Retail Energy Jurisdictional Factor	0.95910	0.96140	0.95640	0.95580	0.93930	0.89320	0.90480	0.90820	0.90910	0.90310	0.96100	0.97020	
6		Retail Transmission Demand Jurisdictional Factor	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	
		Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
		Retail Production Demand Jurisdictional Factor - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
		Retail Production Demand Jurisdictional Factor - Intm	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
		Retail Production Demand Jurisdictional Factor - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
		Retail Production Demand Jurisdictional Factor - A&G	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	
7		Jurisdictional Energy Recoverable Costs (A)	722,307	1,947	712,107	942,954	878,121	1,095,989	1,447,818	832,094	1,054,672	1,445,686	1,504,781	130,323	10,768,799
8		Jurisdictional Demand Recoverable Costs - Transm (B)	11,195	111,227	175,985	28,864	83,214	6,674	24,942	29,323	25,072	13,081	0	4,367	513,944
		Jurisdictional Demand Recoverable Costs - Distrib (B)	(7,680)	2,525	10,357	2,252	2,401	8,872	(45,437)	30,249	(23,876)	0	0	0	(20,337)
		Jurisdictional Demand Recoverable Costs - Prod-Base (B)	1,131,637	1,248,861	2,154,198	1,623,275	899,770	928,868	1,006,878	1,217,584	965,770	1,235,690	730,274	116,174	13,258,979
		Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	2,452	33,725	0	18,099	75,424	(34,315)	49,935	23,991	(655)	0	0	137,713	306,369
		Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
		Jurisdictional Demand Recoverable Costs - A&G (B)	6,395	6,739	8,133	6,538	6,557	6,743	7,342	6,640	4,841	4,579	5,363	4,563	74,433
9		Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,866,306	$1,405,024	$3,060,780	$2,621,982	$1,945,487	$2,012,831	$2,491,478	$2,139,881	$2,025,824	$2,699,036	$2,240,418	$393,140	$24,902,187

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Variance Report of Capital Investment Activities
(In Dollars)

Form 42-6A

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)

Line			(1) Total Year Actual	(2) Actual/ Estimated	(3) Variance Amount	(4) Variance Percent
1	Description of Capital Investment Activities					
	3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline	$410,593	$410,598	($5)	0%
	4.x	Above Ground Tank Secondary Containment	1,255,231	1,260,408	(5,177)	0%
	5	SO2/NOx Emissions Allowances	249,881	251,663	(1,782)	-1%
	6	Phase II Cooling Water Intake 316(b)	207,817	244,199	(36,382)	-15%
	7.x	CAIR/CAMR	8,128,099	8,162,591	(34,492)	0%
	9	Sea Turtle - Coastal Street Lighting	1,031	1,053	(22)	-2%
	10.x	Underground Storage Tanks	21,086	21,192	(106)	-1%
	11	Modular Cooling Towers	0	0	0	0%
	11.1	Crystal River Thermal Discharge Compliance Project	0	0	0	0%
	15.1	Effluent Limitation Guidelines CRN (ELG)	69,287	88,881	(19,594)	-22%
	16	National Pollutant Discharge Elimination System (NPDES)	1,398,615	1,405,468	(6,853)	0%
	17x	Mercury & Air Toxics Standards (MATS)	15,557,001	15,645,294	(88,293)	-1%
	18	Coal Combustion Residual (CCR) Rule	43,709	43,974	(265)	-1%
2	Total Capital Investment Activities - Recoverable Costs		$27,342,350	$27,535,321	($192,971)	-1%
3	Recoverable Costs Allocated to Energy		15,913,995	15,986,748	($72,753)	0%
4	Recoverable Costs Allocated to Demand		$11,428,355	$11,548,573	($120,218)	-1%

Notes:

Column (1) End of Period Totals on Form 42-7A
Column (2) 2019 Actual/Estimated Filing (7/26/2019)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate	$52,469	$52,142	$51,814	$51,489	$51,162	$50,834	50,498	$50,184	$0	$0	$0	$0	$410,593
4.1	Above Ground Tank Secondary Containment - Peaking	120,058	119,581	119,112	73,067	72,883	72,701	72,018	71,839	71,661	71,480	71,304	71,122	1,006,828
4.2	Above Ground Tank Secondary Containment - Base	18,843	18,823	18,804	18,784	18,765	18,745	18,515	18,497	18,477	18,458	18,437	18,418	223,566
4.3	Above Ground Tank Secondary Containment - Intermediate	2,098	2,094	2,091	2,087	2,084	2,080	2,059	2,056	2,052	2,049	2,045	2,042	24,837
5	SO2/NOX Emissions Allowances - Energy	20,983	20,975	20,972	20,982	20,989	20,982	20,688	20,680	20,672	20,664	20,653	20,641	249,881
6	Phase II Cooling Water Intake 316(b) - Base	8,741	9,180	10,205	11,294	12,263	13,456	15,733	18,363	20,415	24,337	29,532	34,298	207,817
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	16,829	16,786	16,743	13,486	13,465	13,442	13,302	13,280	13,259	13,236	13,215	13,194	170,236
7.3	CAMR Crystal River - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
7.4	CAIR/CAMR Crystal River AFUDC - Base	533,976	651,773	659,598	664,739	666,961	670,261	666,192	667,152	667,898	668,488	667,607	666,105	7,850,750
7.4	CAIR/CAMR Crystal River AFUDC - Energy	8,388	7,812	7,822	7,881	8,632	9,277	8,824	9,074	9,040	9,105	10,245	11,013	107,113
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Sea Turtle - Coastal Street Lighting -Distribution	87	87	87	87	87	86	85	85	85	85	85	85	1,031
10.1	Underground Storage Tanks - Base	1,213	1,211	1,210	1,207	1,205	1,203	1,190	1,189	1,187	1,185	1,183	1,181	14,364
10.2	Underground Storage Tanks - Intermediate	569	568	567	565	564	563	558	556	555	554	552	551	6,722
11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
15.1	Effluent Limitation Guidelines CRN (RLG) - Base	2,814	2,825	2,942	3,159	3,281	3,292	3,796	5,547	7,427	9,249	11,193	13,762	69,287
16	National Pollutant Discharge Elimination System (NPDES) - Intermediate	118,302	118,070	117,839	117,608	117,377	117,146	115,949	115,721	115,493	115,265	115,037	114,808	1,398,615
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	28,678	28,636	28,592	28,550	28,507	28,465	28,122	28,080	28,039	27,996	27,954	27,912	339,535
17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	1,095,374	1,093,802	1,092,231	1,090,659	1,089,089	1,087,517	1,075,508	1,073,959	1,072,409	1,070,860	1,069,309	1,067,759	12,978,470
17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	189,920	189,467	189,013	188,561	188,107	187,653	185,497	185,051	184,603	184,156	183,709	183,262	2,238,995
18	Coal Combustion Residual (CCR) Rule - Demand	3,690	3,684	3,679	3,673	3,669	3,664	3,620	3,615	3,610	3,604	3,600	3,595	43,709
2	Total Investment Projects - Recoverable Costs	$2,223,032	$2,337,516	$2,343,321	$2,297,878	$2,299,090	$2,301,367	$2,282,154	$2,284,928	$2,236,882	$2,240,771	$2,245,660	$2,249,748	$27,342,350
3	Recoverable Costs Allocated to Energy	1,343,343	1,340,692	1,338,630	1,336,633	1,335,324	1,333,894	1,318,639	1,316,844	1,314,763	1,312,781	1,311,870	1,310,587	15,913,995
	Recoverable Costs Allocated to Distribution Demand	87	87	87	87	87	86	85	85	85	85	85	85	1,031
4	Recoverable Costs Allocated to Demand - Production - Base	569,277	687,496	696,438	702,856	706,144	710,621	709,046	714,363	719,014	725,321	731,552	737,359	8,409,493
	Recoverable Costs Allocated to Demand - Production - Intermediate	173,438	172,874	172,311	171,749	171,187	170,623	169,064	168,517	118,100	117,868	117,634	117,401	1,840,767
	Recoverable Costs Allocated to Demand - Production - Peaking	136,887	136,367	135,855	86,553	86,348	86,143	85,320	85,119	84,920	84,716	84,519	84,316	1,177,064
5	Retail Energy Jurisdictional Factor	0.95910	0.96140	0.95640	0.95580	0.93930	0.89320	0.90480	0.90820	0.90910	0.90310	0.96100	0.97020	
	Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
6	Retail Demand Jurisdictional Factor - Production - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
7	Jurisdictional Energy Recoverable Costs (B)	1,288,400	1,288,941	1,280,265	1,277,553	1,254,269	1,191,434	1,193,104	1,195,957	1,195,251	1,185,572	1,260,707	1,271,531	14,882,985
	Jurisdictional Demand Recoverable Costs - Distribution (B)	87	87	87	87	87	86	85	85	85	85	85	85	1,026
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	528,773	638,581	646,887	652,848	655,902	660,061	658,598	663,537	667,857	673,715	679,503	684,896	7,811,158
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	126,095	125,685	125,275	124,867	124,458	124,048	122,915	122,517	85,862	85,694	85,523	85,354	1,338,293
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	131,307	130,809	130,318	83,025	82,829	82,632	81,843	81,650	81,459	81,263	81,074	80,879	1,129,087
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$2,074,662	$2,184,102	$2,182,832	$2,138,380	$2,117,545	$2,058,260	$2,056,544	$2,063,745	$2,030,513	$2,026,328	$2,106,891	$2,122,746	$25,162,548

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9; Form 42-8A, Line 5 for Projects 5 - Emission Allowances and Project 7. 4 - Reagents
(B) Line 3 x Line 5
(C) Line 4 x Line 6

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)
Page 9 of 27

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline - Intermediate (Project 3.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3	Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (G)			400,142	350,125	300,108	250,091	200,074	150,057	100,040	50,024	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$400,142	$350,125	$300,108	$250,091	$200,074	$150,057	$100,041	$50,024	$0	$0	$0	$0	$0	
6	Average Net Investment				$375,134	$325,117	$275,100	$225,083	$175,066	$125,049	$75,032	$25,012	$0	$0	$0	$0	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		652	566	478	392	305	217	123	41	0	0	0	0	2,774
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		1,800	1,559	1,319	1,080	840	600	358	119	0	0	0	0	7,675
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (G)				50,017	50,017	50,017	50,017	50,017	50,017	50,017	50,024	0	0	0	0	400,144
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$52,469	$52,142	$51,814	$51,489	$51,162	$50,834	$50,498	$50,184	$0	$0	$0	$0	410,593
	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				$52,469	$52,142	$51,814	$51,489	$51,162	$50,834	$50,498	$50,184	$0	$0	$0	$0	410,593
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)				0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				38,147	37,909	37,670	37,434	37,196	36,958	36,714	36,485	0	0	0	0	298,513
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$38,147	$37,909	$37,670	$37,434	$37,196	$36,958	$36,714	$36,485	$0	$0	$0	$0	$298,513

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed in service. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.

(D) Property tax calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed in service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

(G) Projects 3.1b, 3.1c, and 3.1d are being treated as a regulatory asset and are being amortized over 3 years as approved in Order No. PSC-2016-0535-FOF-EI. Project 3.1a amortized over 26 months as approved in Order No. PSC-2018-0014-FOF-EI.

DUKE ENERGY FLORIDA, LLC
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Peaking (Project 4.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$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	394,968	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$9,235,204	$9,235,204	$9,235,204	$9,235,204	$9,235,204	$9,235,204	$9,235,204	$9,235,204	$9,235,204	$9,235,204	$9,235,204	$9,235,204	$8,840,236	
3	Less: Accumulated Depreciation			(3,410,659)	(3,438,728)	(3,466,797)	(3,494,866)	(3,522,935)	(3,551,004)	(3,579,072)	(3,607,141)	(3,635,210)	(3,663,279)	(3,691,348)	(3,719,417)	(3,522,436)	
3a	Regulatory Asset Balance (G)			137,132	91,425	45,718	0	0	0	0	0	0	0	0	0	169,932	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$5,961,677	$5,887,901	$5,814,125	$5,740,338	$5,712,269	$5,684,200	$5,656,132	$5,628,063	$5,599,994	$5,571,925	$5,543,856	$5,515,787	$5,487,731	
6	Average Net Investment				$5,924,789	$5,851,013	$5,777,232	$5,726,304	$5,698,235	$5,670,166	$5,642,097	$5,614,028	$5,585,960	$5,557,891	$5,529,822	$5,501,759	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		10,303	10,175	10,047	9,959	9,909	9,861	9,247	9,201	9,155	9,108	9,064	9,017	115,046
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		28,103	27,754	27,402	27,163	27,029	26,895	26,826	26,693	26,561	26,427	26,295	26,160	323,308
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)			28,069	28,069	28,069	28,069	28,069	28,069	28,069	28,069	28,069	28,069	28,069	28,069	28,069	336,826
	b. Amortization (G)			45,707	45,707	45,718	0	0	0	0	0	0	0	0	0	0	137,132
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	94,516
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$120,058	$119,581	$119,112	$73,067	$72,883	$72,701	$72,018	$71,839	$71,661	$71,480	$71,304	$71,122	1,006,828	
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. Recoverable Costs Allocated to Demand			$120,058	$119,581	$119,112	$73,067	$72,883	$72,701	$72,018	$71,839	$71,661	$71,480	$71,304	$71,122	1,006,828	
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			115,165	114,707	114,257	70,089	69,912	69,738	69,083	68,911	68,740	68,567	68,398	68,223	965,790	
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$115,165	$114,707	$114,257	$70,089	$69,912	$69,738	$69,083	$68,911	$68,740	$68,567	$68,398	$68,223	$965,790	

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed in service. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed in service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

(G) Project 4.1a (Turner AST) amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.
Project 4.1i (Higgins AST) amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
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Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	$2,399,039	
3	Less: Accumulated Depreciation			(9,151)	(12,183)	(15,215)	(18,247)	(21,279)	(24,311)	(27,343)	(30,375)	(33,407)	(36,439)	(39,471)	(42,503)	(45,535)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,389,888	$2,386,856	$2,383,824	$2,380,792	$2,377,760	$2,374,728	$2,371,696	$2,368,664	$2,365,632	$2,362,600	$2,359,568	$2,356,536	$2,353,504	
6	Average Net Investment				$2,388,372	$2,385,340	$2,382,308	$2,379,276	$2,376,244	$2,373,212	$2,370,180	$2,367,148	$2,364,116	$2,361,084	$2,358,052	$2,355,020	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		4,153	4,148	4,143	4,138	4,133	4,127	3,884	3,880	3,875	3,870	3,864	3,859	48,074
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		11,329	11,314	11,300	11,285	11,271	11,257	11,270	11,256	11,241	11,227	11,212	11,198	135,160
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)			3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	36,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			329	329	329	329	329	329	329	329	329	329	329	329	329	3,948
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$18,843	$18,823	$18,804	$18,784	$18,765	$18,745	$18,515	$18,497	$18,477	$18,458	$18,437	$18,418	223,566	
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. Recoverable Costs Allocated to Demand			$18,843	$18,823	$18,804	$18,784	$18,765	$18,745	$18,515	$18,497	$18,477	$18,458	$18,437	$18,418	223,566	
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885		
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	
13	Retail Demand-Related Recoverable Costs (F)			17,502	17,484	17,466	17,448	17,430	17,411	17,198	17,181	17,162	17,145	17,125	17,108	207,659	
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$17,502	$17,484	$17,466	$17,448	$17,430	$17,411	$17,198	$17,181	$17,162	$17,145	$17,125	$17,108	$207,659	

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-2010-0131-FOF-EI.

(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
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Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	
3	Less: Accumulated Depreciation			(79,086)	(79,611)	(80,136)	(80,661)	(81,186)	(81,711)	(82,236)	(82,761)	(83,286)	(83,811)	(84,336)	(84,861)	(85,386)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$211,211	$210,686	$210,161	$209,636	$209,111	$208,586	$208,061	$207,536	$207,011	$206,486	$205,961	$205,436	$204,911	
6	Average Net Investment				$210,949	$210,424	$209,899	$209,374	$208,849	$208,324	$207,799	$207,274	$206,749	$206,224	$205,699	$205,174	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		367	366	365	364	363	362	341	340	339	338	337	336	4,218
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		1,001	998	996	993	991	988	988	986	983	981	978	976	11,859
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				525	525	525	525	525	525	525	525	525	525	525	525	6,300
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				205	205	205	205	205	205	205	205	205	205	205	205	2,460
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,098	$2,094	$2,091	$2,087	$2,084	$2,080	$2,059	$2,056	$2,052	$2,049	$2,045	$2,042	24,837
	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				$2,098	$2,094	$2,091	$2,087	$2,084	$2,080	$2,059	$2,056	$2,052	$2,049	$2,045	$2,042	24,837
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)				0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				1,525	1,522	1,520	1,517	1,515	1,512	1,497	1,495	1,492	1,490	1,487	1,485	18,057
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,525	$1,522	$1,520	$1,517	$1,515	$1,512	$1,497	$1,495	$1,492	$1,490	$1,487	$1,485	$18,057

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
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Witness: C. A. Menendez
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SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0158150 SO2 Emission Allowance Inventory			$3,237,649	$3,235,988	$3,235,258	$3,235,258	$3,238,407	$3,237,361	$3,236,314	$3,235,060	$3,233,665	$3,232,533	$3,231,124	$3,229,160	$3,227,480	$3,227,480
	b. 0254020 Auctioned SO2 Allowance			304	0	0	0	(132)	0	0	0	0	0	0	0	0	$0
	c. 0158170 NOx Emission Allowance Inventory			0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Working Capital			$3,237,953	$3,235,988	$3,235,258	$3,235,258	$3,238,275	$3,237,361	$3,236,314	$3,235,060	$3,233,665	$3,232,533	$3,231,124	$3,229,160	$3,227,480	$3,227,480
3	Average Net Investment				$3,236,970	$3,235,623	$3,235,258	$3,236,767	$3,237,818	$3,236,838	$3,235,687	$3,234,363	$3,233,099	$3,231,828	$3,230,142	$3,228,320	
4	Return on Average Net Working Capital Balance (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		5,629	5,627	5,626	5,629	5,631	5,629	5,303	5,301	5,299	5,297	5,294	5,291	65,556
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		15,354	15,348	15,346	15,353	15,358	15,353	15,385	15,379	15,373	15,367	15,359	15,350	184,325
5	Total Return Component (C)				$20,983	$20,975	$20,972	$20,982	$20,989	$20,982	$20,688	$20,680	$20,672	$20,664	$20,653	$20,641	249,881
6	Expense Dr (Cr)																
	a. 0509030 SO_2 Allowance Expense				$1,661	$729	$0	($3,148)	$1,046	$1,046	$1,254	$1,396	$1,132	$1,409	$1,964	$1,680	$10,169
	b. 0407426 Amortization Expense				$304	$0	$0	$0	($132)	$0	$0	$0	$0	$0	$0	$0	172
	c. 0509212 NOx Allowance Expense				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	d. Other				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
7	Net Expense (D)				1,965	729	0	(3,148)	914	1,046	1,254	1,396	1,132	1,409	1,964	1,680	10,341
8	Total System Recoverable Expenses (Lines 5 + 7 + 8)				$22,948	$21,704	$20,972	$17,834	$21,903	$22,028	$21,942	$22,076	$21,804	$22,073	$22,617	$22,321	260,222
	a. Recoverable Costs Allocated to Energy				22,948	21,704	20,972	17,834	21,903	22,028	21,942	22,076	21,804	22,073	22,617	22,321	260,222
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
9	Energy Jurisdictional Factor				0.95910	0.96140	0.95640	0.95580	0.93930	0.89320	0.90480	0.90820	0.90910	0.90310	0.96100	0.97020	
10	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (E)				$22,010	$20,867	$20,058	$17,046	$20,574	$19,675	$19,853	$20,049	$19,822	$19,934	$21,734	$21,656	243,277
12	Retail Demand-Related Recoverable Costs (F)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$22,010	$20,867	$20,058	$17,046	$20,574	$19,675	$19,853	$20,049	$19,822	$19,934	$21,734	$21,656	$243,277

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 5 is reported on Capital Schedule

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

(E) Line 8a x Line 9

(F) Line 8b x Line 10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)
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Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Base (Project 6)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$73,881	$61,552	$254,624	$81,175	$218,045	$150,013	$619,630	$203,122	$438,666	$788,459	$836,542	$654,129	$4,379,838
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			1,311,525	1,385,406	1,446,958	1,701,582	1,782,757	2,000,801	2,150,814	2,770,444	2,973,567	3,412,232	4,200,692	5,037,234	5,691,363	
5	Net Investment (Lines 2 + 3 + 4)			$1,311,525	$1,385,406	$1,446,958	$1,701,582	$1,782,757	$2,000,801	$2,150,814	$2,770,444	$2,973,567	$3,412,232	$4,200,692	$5,037,234	$5,691,363	
6	Average Net Investment				$1,348,465	$1,416,182	$1,574,270	$1,742,169	$1,891,779	$2,075,808	$2,460,629	$2,872,005	$3,192,900	$3,806,462	$4,618,963	$5,364,299	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		2,345	2,463	2,738	3,030	3,290	3,610	4,033	4,707	5,233	6,238	7,570	8,792	54,049
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		6,396	6,717	7,467	8,264	8,973	9,846	11,700	13,656	15,182	18,099	21,962	25,506	153,768
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	1.4860%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.001703			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$8,741	$9,180	$10,205	$11,294	$12,263	$13,456	$15,733	$18,363	$20,415	$24,337	$29,532	$34,298	207,817
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$8,741	$9,180	$10,205	$11,294	$12,263	$13,456	$15,733	$18,363	$20,415	$24,337	$29,532	$34,298	207,817
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				8,119	8,527	9,479	10,490	11,390	12,499	14,614	17,056	18,962	22,605	27,431	31,858	193,031
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$8,119	$8,527	$9,479	$10,490	$11,390	$12,499	$14,614	$17,056	$18,962	$22,605	$27,431	$31,858	$193,031

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	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	347,198	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,802,096	$1,802,096	$1,802,096	$1,802,096	$1,802,096	$1,802,096	$1,802,096	$1,802,096	$1,802,096	$1,802,096	$1,802,096	$1,802,096	$1,454,898	
3	Less: Accumulated Depreciation			(451,809)	(455,223)	(458,637)	(462,051)	(465,465)	(468,879)	(472,293)	(475,707)	(479,121)	(482,535)	(485,949)	(489,363)	(385,464)	
3a	Regulatory Asset Balance (G)			9,674	6,450	3,225	(0)	0	0	0	0	0	0	0	0	239,885	
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)			$1,359,961	$1,353,323	$1,346,684	$1,340,045	$1,336,631	$1,333,217	$1,329,803	$1,326,389	$1,322,975	$1,319,561	$1,316,147	$1,312,733	$1,309,319	
6	Average Net Investment				$1,356,642	$1,350,003	$1,343,364	$1,338,338	$1,334,924	$1,331,510	$1,328,096	$1,324,682	$1,321,268	$1,317,854	$1,314,440	$1,311,026	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		2,359	2,347	2,336	2,327	2,322	2,316	2,176	2,171	2,166	2,159	2,155	2,149	26,983
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		6,435	6,404	6,372	6,349	6,333	6,316	6,316	6,299	6,283	6,267	6,250	6,235	75,859
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	Varies			3,414	3,414	3,414	3,414	3,414	3,414	3,414	3,414	3,414	3,414	3,414	3,414	40,968
	b. Amortization (G)				3,225	3,225	3,225	0	0	0	0	0	0	0	0	0	9,674
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	Varies			1,396	1,396	1,396	1,396	1,396	1,396	1,396	1,396	1,396	1,396	1,396	1,396	16,752
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$16,829	$16,786	$16,743	$13,486	$13,465	$13,442	$13,302	$13,280	$13,259	$13,236	$13,215	$13,194	170,236
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$16,829	$16,786	$16,743	$13,486	$13,465	$13,442	$13,302	$13,280	$13,259	$13,236	$13,215	$13,194	170,236
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)				0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				16,143	16,102	16,060	12,936	12,916	12,894	12,760	12,739	12,719	12,697	12,676	12,656	163,298
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$16,143	$16,102	$16,060	$12,936	$12,916	$12,894	$12,760	$12,739	$12,719	$12,697	$12,676	$12,656	$163,298

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed in service. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Property tax calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

(G) Project 7.2g (Turner CT) amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.
Project 7.2e (Higgins CT) amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA, LLC
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Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$1,371,979	$1,237,479	$974,639	$579,883	$225,674	$708,445	$408,167	$77,771	$262,092	$99,698	($108,285)	($98,859)	$5,738,684
	b. Clearings to Plant				0	79,482,748	974,639	579,883	225,674	708,445	408,167	77,771	262,092	99,698	(108,285)	(98,859)	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$3,930,012	$3,930,012	$83,412,760	$84,387,399	$84,967,282	$85,192,956	$85,901,401	$86,309,568	$86,387,339	$86,649,431	$86,749,129	$86,640,844	$86,541,985	
3	Less: Accumulated Depreciation			($367,488)	(375,074)	(481,086)	(588,305)	(696,243)	(804,460)	(913,554)	(1,023,154)	(1,132,850)	(1,242,871)	(1,353,015)	(1,463,025)	(1,572,913)	
4	CWIP - AFUDC-Interest Bearing			76,873,290	78,245,269	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$80,435,815	$81,800,207	$82,931,675	$83,799,095	$84,271,039	$84,388,497	$84,987,848	$85,286,415	$85,254,490	$85,406,560	$85,396,115	$85,177,820	$84,969,073	
6	Average Net Investment				$81,123,945	$82,365,941	$83,365,385	$84,035,067	$84,329,768	$84,688,172	$85,137,131	$85,270,452	$85,330,525	$85,401,338	$85,286,967	$85,073,447	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		141,064	143,235	144,973	146,137	146,649	147,272	139,533	139,751	139,850	139,966	139,779	139,428	1,707,637
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		384,768	390,689	395,430	398,606	400,005	401,704	404,811	405,445	405,730	406,067	405,523	404,508	4,803,286
	c. Other (F)				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				7,586	106,012	107,219	107,938	108,217	109,094	109,600	109,696	110,021	110,144	110,010	109,888	1,205,425
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				558	11,837	11,976	12,058	12,090	12,191	12,248	12,260	12,297	12,311	12,295	12,281	134,402
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$533,976	$651,773	$659,598	$664,739	$666,961	$670,261	$666,192	$667,152	$667,898	$668,488	$667,607	$666,105	7,850,750
	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				$533,976	$651,773	$659,598	$664,739	$666,961	$670,261	$666,192	$667,152	$667,898	$668,488	$667,607	$666,105	7,850,750
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				495,984	605,399	612,668	617,443	619,507	622,572	618,792	619,684	620,377	620,925	620,107	618,712	7,292,169
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$495,984	$605,399	$612,668	$617,443	$619,507	$622,572	$618,792	$619,684	$620,377	$620,925	$620,107	$618,712	$7,292,169

Notes:
(A) N/A
(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
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Schedule of Amortization and Return
For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0154401 Ammonia Inventory			$74,264	$49,071	$32,745	$13,530	$62,259	$107,068	$184,972	$274,070	$321,347	$385,742	$452,347	$546,884	$542,621	542,621
	b. 0154200 Limestone Inventory (F)			1,283,532	1,181,071	1,147,202	1,219,817	1,135,901	1,357,936	1,212,154	1,089,080	1,153,830	966,986	1,042,907	1,162,488	1,193,107	1,193,107
2	Total Working Capital			$1,357,797	1,230,142	1,179,947	1,233,347	1,198,160	1,465,004	1,397,126	1,363,151	1,475,178	1,352,727	1,495,254	1,709,372	1,735,728	1,735,728
3	Average Net Investment				1,293,969	1,205,045	1,206,647	1,215,754	1,331,582	1,431,065	1,380,138	1,419,164	1,413,953	1,423,991	1,602,313	1,722,550	
4	Return on Average Net Working Capital Balance (A)	Jan-Jun	Jul-Dec														
	a. Debt Component (F)	2.09%	1.97%		2,250	2,096	2,098	2,114	2,316	2,489	2,262	2,326	2,317	2,334	2,626	2,823	$28,051
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		6,138	5,716	5,724	5,767	6,316	6,788	6,562	6,748	6,723	6,771	7,619	8,190	79,062
5	Total Return Component (B)				8,388	7,812	7,822	7,881	8,632	9,277	8,824	9,074	9,040	9,105	10,245	11,013	107,113
6	Expense Dr (Cr)																
	a. 502030 Ammonia Expense				176,215	16,575	171,157	179,926	113,375	211,577	240,033	152,992	212,666	292,614	240,612	4,263	2,012,005
	b. 502040 Limestone Expense				225,019	26,083	255,161	222,037	256,686	374,564	702,140	262,766	378,075	530,050	493,292	3,648	3,729,521
	c. 502050 Dibasic Acid Expense				0	0	0	0	0	0	0	0	21,590	0	0	0	21,590
	d. 502070 Gypsum Disposal/Sale				(34,022)	(4,608)	(24,525)	(24,522)	(34,907)	(33,916)	(40,727)	(7,203)	(31,712)	(45,252)	(44,906)	(13,347)	(339,647)
	e. 502040 Hydrated Lime Expense				130,092	13,919	149,377	154,002	163,936	219,412	246,947	145,334	227,190	277,893	236,407	0	1,964,511
	f. 502300 Caustic Expense				8,314	16,437	22,503	4,224	0	0	64,508	16,844	66,745	188,129	146,492	0	534,197
7	Net Expense (C)				505,618	68,407	573,674	535,668	499,090	771,638	1,212,902	570,733	874,553	1,243,435	1,071,896	(5,436)	7,922,177
8	Total System Recoverable Expenses (Lines 5 + 7)				$514,006	$76,219	$581,496	$543,549	$507,722	$780,915	$1,221,726	$579,807	$883,593	$1,252,540	$1,082,141	$5,577	$8,029,290
	a. Recoverable Costs Allocated to Energy				514,006	76,219	581,496	543,549	507,722	780,915	1,221,726	579,807	883,593	1,252,540	1,082,141	5,577	$8,029,290
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Energy Jurisdictional Factor				0.95910	0.96140	0.95640	0.95580	0.93930	0.89320	0.90480	0.90820	0.90910	0.90310	0.96100	0.97020	
10	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)				$492,983	$73,277	$556,142	$519,524	$476,903	$697,513	$1,105,417	$526,581	$803,275	$1,131,169	$1,039,937	$5,411	$7,428,132
12	Retail Demand-Related Recoverable Costs (E)				0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)				$492,983	$73,277	$556,142	$519,524	$476,903	$697,513	$1,105,417	$526,581	$803,275	$1,131,169	$1,039,937	$5,411	$7,428,132

Notes:

(A) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(B) Line 5 is reported on Capital Schedule

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

(D) Line 8a x Line 9

(E) Line 8b x Line 10

DUKE ENERGY FLORIDA, LLC
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Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	$11,324	
3	Less: Accumulated Depreciation			($3,698)	(3,727)	(3,756)	(3,785)	(3,814)	(3,843)	(3,872)	(3,901)	(3,930)	(3,959)	(3,988)	(4,017)	(4,046)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$7,626	$7,597	$7,568	$7,539	$7,510	$7,481	$7,452	$7,423	$7,394	$7,365	$7,336	$7,307	$7,278	
6	Average Net Investment				$7,612	$7,583	$7,554	$7,525	$7,496	$7,467	$7,438	$7,409	$7,380	$7,351	$7,322	$7,293	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		13	13	13	13	13	13	12	12	12	12	12	12	150
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		36	36	36	36	36	35	35	35	35	35	35	35	425
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	3.0658%			29	29	29	29	29	29	29	29	29	29	29	29	348
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.9414%			9	9	9	9	9	9	9	9	9	9	9	9	108
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$87	$87	$87	$87	$87	$86	$85	$85	$85	$85	$85	$85	1,031
	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				$87	$87	$87	$87	$87	$86	$85	$85	$85	$85	$85	$85	1,031
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)				0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				87	87	87	87	87	86	85	85	85	85	85	85	1,026
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$87	$87	$87	$87	$87	$86	$85	$85	$85	$85	$85	$85	$1,026

Notes:
(A) N/A
(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
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Duke Energy Florida
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Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Base (Project 10.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	$168,941	
3	Less: Accumulated Depreciation			(46,000)	(46,296)	(46,592)	(46,888)	(47,184)	(47,480)	(47,776)	(48,072)	(48,368)	(48,664)	(48,960)	(49,256)	(49,552)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$122,941	$122,645	$122,349	$122,053	$121,757	$121,461	$121,165	$120,869	$120,573	$120,277	$119,981	$119,685	$119,389	
6	Average Net Investment				$122,793	$122,497	$122,201	$121,905	$121,609	$121,313	$121,017	$120,721	$120,425	$120,129	$119,833	$119,537	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		214	213	213	212	211	211	198	198	197	197	196	196	2,456
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		582	581	580	578	577	575	575	574	573	571	570	568	6,904
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	2.1000%			296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.8573%			121	121	121	121	121	121	121	121	121	121	121	121	1,452
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,213	$1,211	$1,210	$1,207	$1,205	$1,203	$1,190	$1,189	$1,187	$1,185	$1,183	$1,181	14,364
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,213	$1,211	$1,210	$1,207	$1,205	$1,203	$1,190	$1,189	$1,187	$1,185	$1,183	$1,181	14,364
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				1,127	1,125	1,124	1,121	1,119	1,117	1,105	1,104	1,103	1,101	1,099	1,097	13,342
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,127	$1,125	$1,124	$1,121	$1,119	$1,117	$1,105	$1,104	$1,103	$1,101	$1,099	$1,097	$13,342

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

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Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	$76,006	
3	Less: Accumulated Depreciation			($29,093)	(29,296)	(29,499)	(29,702)	(29,905)	(30,108)	(30,311)	(30,514)	(30,717)	(30,920)	(31,123)	(31,326)	(31,529)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$46,913	$46,710	$46,507	$46,304	$46,101	$45,898	$45,695	$45,492	$45,289	$45,086	$44,883	$44,680	$44,477	
6	Average Net Investment				$46,812	$46,609	$46,406	$46,203	$46,000	$45,797	$45,594	$45,391	$45,188	$44,985	$44,782	$44,579	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		81	81	81	80	80	80	75	74	74	74	73	73	926
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		222	221	220	219	218	217	217	216	215	214	213	212	2,604
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	3.2000%			203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.9890%			63	63	63	63	63	63	63	63	63	63	63	63	756
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$569	$568	$567	$565	$564	$563	$558	$556	$555	$554	$552	$551	6,722
	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				$569	$568	$567	$565	$564	$563	$558	$556	$555	$554	$552	$551	6,722
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)				0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				414	413	412	411	410	409	406	404	404	403	401	401	4,887
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$414	$413	$412	$411	$410	$409	$406	$404	$404	$403	$401	$401	$4,887

Notes:
(A) N/A
(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Return on Capital Investments, Depreciation and Taxes
For Project: Effluent Limitation Guidelines CRN - Base (Project 15.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$2,974	$395	$35,883	$31,049	$6,508	($2,945)	$174,721	$372,709	$215,372	$354,568	$253,620	$549,868	$1,994,721
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3	Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			432,564	435,537	435,933	471,816	502,864	509,372	506,427	681,148	1,053,857	1,269,229	1,623,797	1,877,417	2,427,284	
5	Net Investment (Lines 2 + 3 + 4)			$432,564	$435,537	$435,933	$471,816	$502,864	$509,372	$506,427	$681,148	$1,053,857	$1,269,229	$1,623,797	$1,877,417	$2,427,284	
6	Average Net Investment				$434,051	$435,735	$453,874	$487,340	$506,118	$507,900	$593,788	$867,502	$1,161,543	$1,446,513	$1,750,607	$2,152,350	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		755	758	789	847	880	883	973	1,422	1,904	2,371	2,869	3,528	17,979
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		2,059	2,067	2,153	2,312	2,401	2,409	2,823	4,125	5,523	6,878	8,324	10,234	51,308
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	2.4700%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.1703%			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)				$2,814	$2,825	$2,942	$3,159	$3,281	$3,292	$3,796	$5,547	$7,427	$9,249	$11,193	$13,762	69,287
	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				$2,814	$2,825	$2,942	$3,159	$3,281	$3,292	$3,796	$5,547	$7,427	$9,249	$11,193	$13,762	69,287
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)				2,614	2,624	2,733	2,934	3,048	3,058	3,526	5,152	6,899	8,591	10,397	12,783	64,357
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$2,614	$2,624	$2,733	$2,934	$3,048	$3,058	$3,526	$5,152	$6,899	$8,591	$10,397	$12,783	$64,357

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: NPDES - Intermediate (Project 16)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	$12,841,870	
3	Less: Accumulated Depreciation		($1,716,510)	(1,752,182)	(1,787,854)	(1,823,526)	(1,859,198)	(1,894,870)	(1,930,542)	(1,966,214)	(2,001,886)	(2,037,558)	(2,073,230)	(2,108,902)	(2,144,574)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$11,125,360	$11,089,688	$11,054,016	$11,018,344	$10,982,672	$10,947,000	$10,911,328	$10,875,656	$10,839,984	$10,804,312	$10,768,640	$10,732,968	$10,697,296	
6	Average Net Investment			$11,107,524	$11,071,852	$11,036,180	$11,000,508	$10,964,836	$10,929,164	$10,893,492	$10,857,820	$10,822,148	$10,786,476	$10,750,804	$10,715,132	
7	Return on Average Net Investment (B)	Jan-Jun Jul-Dec														
	a. Debt Component	2.09% 1.97%		19,316	19,254	19,192	19,130	19,068	19,006	17,854	17,795	17,737	17,678	17,620	17,561	221,211
	b. Equity Component Grossed Up For Taxes	5.69% 5.71%		52,687	52,517	52,348	52,179	52,010	51,841	51,796	51,627	51,457	51,288	51,118	50,948	621,816
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.3333%		35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	428,064
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.9930%		10,627	10,627	10,627	10,627	10,627	10,627	10,627	10,627	10,627	10,627	10,627	10,627	127,524
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$118,302	$118,070	$117,839	$117,608	$117,377	$117,146	$115,949	$115,721	$115,493	$115,265	$115,037	$114,808	1,398,615
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$118,302	$118,070	$117,839	$117,608	$117,377	$117,146	$115,949	$115,721	$115,493	$115,265	$115,037	$114,808	1,398,615
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
13	Retail Demand-Related Recoverable Costs (F)			86,009	85,840	85,672	85,505	85,337	85,169	84,298	84,133	83,967	83,801	83,635	83,469	1,016,835
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$86,009	$85,840	$85,672	$85,505	$85,337	$85,169	$84,298	$84,133	$83,967	$83,801	$83,635	$83,469	$1,016,835

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 4 & 5 - Energy (Project 17)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	$3,690,187	
3	Less: Accumulated Depreciation			($266,981)	(273,563)	(280,145)	(286,727)	(293,309)	(299,891)	(306,473)	(313,055)	(319,637)	(326,219)	(332,801)	(339,383)	(345,965)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$3,423,206	$3,416,624	$3,410,042	$3,403,460	$3,396,878	$3,390,296	$3,383,714	$3,377,132	$3,370,550	$3,363,968	$3,357,386	$3,350,804	$3,344,222	
6	Average Net Investment				$3,419,915	$3,413,333	$3,406,751	$3,400,169	$3,393,587	$3,387,005	$3,380,423	$3,373,841	$3,367,259	$3,360,677	$3,354,095	$3,347,513	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		5,947	5,936	5,924	5,913	5,901	5,890	5,540	5,529	5,519	5,508	5,497	5,486	68,590
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		16,222	16,191	16,159	16,128	16,097	16,066	16,073	16,042	16,011	15,979	15,948	15,917	192,833
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	Blended			6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	78,984
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.1703%			524	524	524	524	524	524	524	524	524	524	524	524	6,288
	e. Other (E)				(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(7,160)
9	Total System Recoverable Expenses (Lines 7 + 8)				$28,678	$28,636	$28,592	$28,550	$28,507	$28,465	$28,122	$28,080	$28,039	$27,996	$27,954	$27,912	339,535
	a. Recoverable Costs Allocated to Energy				28,678	28,636	28,592	28,550	28,507	28,465	28,122	28,080	28,039	27,996	27,954	27,912	339,535
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.95910	0.96140	0.95640	0.95580	0.93930	0.89320	0.90480	0.90820	0.90910	0.90310	0.96100	0.97020	
11	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)				$27,505	$27,531	$27,346	$27,288	$26,777	$25,425	$25,445	$25,503	$25,491	$25,284	$26,864	$27,081	317,539
13	Retail Demand-Related Recoverable Costs (G)				0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$27,505	$27,531	$27,346	$27,288	$26,777	$25,425	$25,445	$25,503	$25,491	$25,284	$26,864	$27,081	$317,539

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.

(F) Line 9a x Line 10

(G) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - ANCLOTE GAS CONVERSION - Energy (Project 17.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	$133,918,267	
3	Less: Accumulated Depreciation			($14,548,630)	(14,791,044)	(15,033,458)	(15,275,872)	(15,518,286)	(15,760,700)	(16,003,114)	(16,245,528)	(16,487,942)	(16,730,356)	(16,972,770)	(17,215,184)	(17,457,598)	
4	CWIP - AFUDC Bearing			($0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)			$119,369,637	$119,127,223	$118,884,809	$118,642,395	$118,399,981	$118,157,567	$117,915,153	$117,672,739	$117,430,325	$117,187,911	$116,945,497	$116,703,083	$116,460,669	
6	Average Net Investment				$119,248,430	$119,006,016	$118,763,602	$118,521,188	$118,278,774	$118,036,360	$117,793,946	$117,551,532	$117,309,118	$117,066,704	$116,824,290	$116,581,876	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		207,373	206,951	206,530	206,108	205,687	205,265	193,054	192,657	192,260	191,863	191,465	191,068	2,390,281
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		565,634	564,484	563,334	562,184	561,035	559,885	560,087	558,935	557,782	556,630	555,477	554,324	6,719,791
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	2.1722%			242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	2,908,968
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.8490%			94,747	94,747	94,747	94,747	94,747	94,747	94,747	94,747	94,747	94,747	94,747	94,747	1,136,964
	e. Other (E)				(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(177,534)
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,095,374	$1,093,802	$1,092,231	$1,090,659	$1,089,089	$1,087,517	$1,075,508	$1,073,959	$1,072,409	$1,070,860	$1,069,309	$1,067,759	12,978,470
	a. Recoverable Costs Allocated to Energy				1,095,374	1,093,802	1,092,231	1,090,659	1,089,089	1,087,517	1,075,508	1,073,959	1,072,409	1,070,860	1,069,309	1,067,759	12,978,470
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.95910	0.96140	0.95640	0.95580	0.93930	0.89320	0.90480	0.90820	0.90910	0.90310	0.96100	0.97020	
11	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)				$1,050,573	$1,051,581	$1,044,609	$1,042,451	$1,022,981	$971,370	$973,119	$975,369	$974,927	$967,093	$1,027,605	$1,035,939	12,137,618
13	Retail Demand-Related Recoverable Costs (G)				0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,050,573	$1,051,581	$1,044,609	$1,042,451	$1,022,981	$971,370	$973,119	$975,369	$974,927	$967,093	$1,027,605	$1,035,939	$12,137,618

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.

(F) Line 9a x Line 10

(G) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 1 & 2 - Energy (Project 17.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	$22,681,074	
3	Less: Accumulated Depreciation		($3,006,977)	(3,076,910)	(3,146,844)	(3,216,777)	(3,286,710)	(3,356,644)	(3,426,577)	(3,496,510)	(3,566,443)	(3,636,377)	(3,706,310)	(3,776,243)	(3,846,177)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$19,674,097	$19,604,163	$19,534,230	$19,464,297	$19,394,363	$19,324,430	$19,254,497	$19,184,563	$19,114,630	$19,044,697	$18,974,763	$18,904,830	$18,834,897	
6	Average Net Investment			$19,639,130	$19,569,197	$19,499,263	$19,429,330	$19,359,397	$19,289,463	$19,219,530	$19,149,597	$19,079,663	$19,009,730	$18,939,797	$18,869,863	
7	Return on Average Net Investment (B)	Jan-Jun Jul-Dec														
	a. Debt Component	2.09% 1.97%		34,152	34,031	33,909	33,788	33,666	33,544	31,499	31,385	31,270	31,155	31,041	30,926	390,366
	b. Equity Component Grossed Up For Taxes	5.69% 5.71%		93,155	92,823	92,491	92,160	91,828	91,496	91,385	91,053	90,720	90,388	90,055	89,723	1,097,277
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.7000%		69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	839,200
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.1703%		3,219	3,219	3,219	3,219	3,219	3,219	3,219	3,219	3,219	3,219	3,219	3,219	38,628
	e. Other (E)			(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(126,475)
9	Total System Recoverable Expenses (Lines 7 + 8)			$189,920	$189,467	$189,013	$188,561	$188,107	$187,653	$185,497	$185,051	$184,603	$184,156	$183,709	$183,262	2,238,995
	a. Recoverable Costs Allocated to Energy			189,920	189,467	189,013	188,561	188,107	187,653	185,497	185,051	184,603	184,156	183,709	183,262	2,238,995
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.95910	0.96140	0.95640	0.95580	0.93930	0.89320	0.90480	0.90820	0.90910	0.90310	0.96100	0.97020	
11	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)			$182,152	$182,153	$180,772	$180,226	$176,689	$167,611	$167,837	$168,063	$167,822	$166,311	$176,544	$177,800	2,093,982
13	Retail Demand-Related Recoverable Costs (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$182,152	$182,153	$180,772	$180,226	$176,689	$167,611	$167,837	$168,063	$167,822	$166,311	$176,544	$177,800	$2,093,982

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.

(F) Line 9a x Line 10

(G) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2019 - December 2019

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)
Page 26 of 27

Return on Capital Investments, Depreciation and Taxes
For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Base (Project 18)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$17	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17
	b. Clearings to Plant				17	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$446,073	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	
3	Less: Accumulated Depreciation			(10,574)	(11,380)	(12,187)	(12,993)	(13,800)	(14,606)	(15,413)	(16,219)	(17,026)	(17,832)	(18,639)	(19,445)	(20,252)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$435,499	$434,710	$433,903	$433,097	$432,290	$431,484	$430,677	$429,871	$429,064	$428,258	$427,451	$426,645	$425,838	
6	Average Net Investment				$435,105	$434,306	$433,500	$432,693	$431,887	$431,080	$430,274	$429,467	$428,661	$427,854	$427,048	$426,241	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		757	755	754	752	751	750	705	704	703	701	700	699	8,731
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		2,064	2,060	2,056	2,052	2,049	2,045	2,046	2,042	2,038	2,034	2,031	2,027	24,544
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	2.1695%			806	806	806	806	806	806	806	806	806	806	806	806	9,678
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.1703%			63	63	63	63	63	63	63	63	63	63	63	63	756
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$3,690	$3,684	$3,679	$3,673	$3,669	$3,664	$3,620	$3,615	$3,610	$3,604	$3,600	$3,595	43,709
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,690	$3,684	$3,679	$3,673	$3,669	$3,664	$3,620	$3,615	$3,610	$3,604	$3,600	$3,595	43,703
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				3,427	3,422	3,417	3,412	3,408	3,403	3,362	3,358	3,353	3,348	3,344	3,339	40,594
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$3,427	$3,422	$3,417	$3,412	$3,408	$3,403	$3,362	$3,358	$3,353	$3,348	$3,344	$3,339	$40,594

Notes:

(A) N/A

(B) Jan - Jun 2019 Line 6 x 7.78% x 1/12. Jul - Dec 2019 Line 6 x 7.67% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% (Jan-Jun) and 4.31% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2018 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2019 - December 2019

Capital Structure and Cost Rates

Form 42-9A

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)

Class of Capital	Retail Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$4,374,787,363	40.92%	0.10500	4.30%	5.69%
PS	-	0.00%	0.00000	0.00%	0.00%
LTD	4,497,051,945	42.06%	0.04896	2.06%	2.06%
STD	(193,058,184)	-1.81%	0.00878	-0.02%	-0.02%
CD-Active	179,648,841	1.68%	0.02352	0.04%	0.04%
CD-Inactive	1,597,098	0.01%	0.00000	0.00%	0.00%
ADIT	1,826,908,909	17.09%	0.00000	0.00%	0.00%
FAS 109	-	0.00%	0.00000	0.00%	0.00%
ITC	5,239,408	0.05%	0.07853	0.00%	0.00%
Total	$ 10,692,175,379	100.00%		6.38%	7.78%
			Total Debt	2.09%	2.09%
			Total Equity	4.30%	5.69%

May 2018 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

The Pre-Tax Weighted Cost rate for 2019 reflects the updated Florida State Corporate Tax Rate.

Class of Capital	Retail Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$ 4,874,577,393	41.01%	0.10500	4.31%	5.71%
PS	-	0.00%	0.00000	0.00%	0.00%
LTD	4,845,025,196	40.77%	0.04701	1.92%	1.92%
STD	(59,426,995)	-0.50%	-0.00358	0.00%	0.00%
CD-Active	176,756,874	1.49%	0.02378	0.04%	0.04%
CD-Inactive	1,853,499	0.02%	0.00000	0.00%	0.00%
ADIT	2,026,313,275	17.05%	0.00000	0.00%	0.00%
FAS 109	-	0.00%	0.00000	0.00%	0.00%
ITC	19,805,922	0.17%	0.07715	0.01%	0.01%
Total	$11,884,905,162	100.00%		6.27%	7.67%
			Total Debt	1.97%	1.97%
			Total Equity	4.31%	5.71%

May 2019 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

The Pre-Tax Weighted Cost rate for 2019 reflects the updated Florida State Corporate Tax Rate.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Capital Program Detail

January 2019 - December 2019
Final True-Up
Docket No. 20200007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 22
PARTY: CAM-2
DESCRIPTION: Capital Program
DetailJanuary 2019 – December 2019

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
Pipeline Intergrity Management (Project 3 Recap)

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (C)			7,285	6,375	5,465	4,556	3,646	2,736	1,826	917	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$7,285	$6,375	$5,466	$4,556	$3,646	$2,736	$1,827	$917	$0	$0	$0	$0	$0	
6	Average Net Investment				6,830	5,921	5,011	4,101	3,191	2,281	1,372	459	0	0	0	0	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		12	10	9	7	6	4	2	1	0	0	0	0	51
	b. Equity Component Grossed Up For Taxes	5.75%	5.71%		33	28	24	20	15	11	7	2	0	0	0	0	140
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.8857%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (C)				910	910	910	910	910	910	910	917	0	0	0	0	7,287
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009772			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)				$955	$948	$943	$937	$931	$925	$919	$920	$0	$0	$0	$0	$7,478
	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				$955	$948	$943	$937	$931	$925	$919	$920	$0	$0	$0	$0	$7,478

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3	Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (B)			208,586	182,512	156,439	130,366	104,293	78,220	52,146	26,073	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$208,586	$182,512	$156,439	$130,366	$104,293	$78,220	$52,146	$26,073	$0	$0	$0	$0	$0	
6	Average Net Investment				195,549	169,476	143,403	117,329	91,256	65,183	39,110	13,037	0	0	0	0	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		340	295	249	204	159	113	64	21	0	0	0	0	1,445
	b. Equity Component Grossed Up For Taxes	5.75%	5.71%		938	813	688	563	438	313	186	62	0	0	0	0	4,001
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.5579%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (B)				26,073	26,073	26,073	26,073	26,073	26,073	26,073	26,073	0	0	0	0	208,586
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009772			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)				$27,351	$27,181	$27,010	$26,840	$26,670	$26,499	$26,323	$26,156	$0	$0	$0	$0	$214,032
	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				$27,351	$27,181	$27,010	$26,840	$26,670	$26,499	$26,323	$26,156	$0	$0	$0	$0	$214,032

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) Investment amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.
(C) Investment amortized over 26 months, as approved in Order PSC-2018-0014-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
Pipeline Intergrity Management (Project 3 Recap)

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation			$0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (B)			$159,001	139,126	119,251	99,376	79,501	59,626	39,750	19,875	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$159,001	$139,126	$119,251	$99,376	$79,501	$59,626	$39,750	$19,875	$0	$0	$0	$0	$0	
6	Average Net Investment				149,064	129,189	109,313	89,438	69,563	49,688	29,813	9,938	0	0	0	0	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		259	225	190	156	121	86	49	16	0	0	0	0	1,102
	b. Equity Component Grossed Up For Taxes	5.75%	5.71%		715	620	524	429	334	238	142	47	0	0	0	0	3,049
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.5579%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (B)				19,875	19,875	19,875	19,875	19,875	19,875	19,875	19,875	0	0	0	0	159,001
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009772			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)				$20,849	$20,720	$20,589	$20,460	$20,330	$20,199	$20,066	$19,938	$0	$0	$0	$0	$163,152
	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				$20,849	$20,720	$20,589	$20,460	$20,330	$20,199	$20,066	$19,938	$0	$0	$0	$0	$163,152

For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3	Less: Accumulated Depreciation			$0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (B)			$25,270	22,111	18,952	15,794	12,635	9,476	6,317	3,159	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$25,270	$22,111	$18,952	$15,794	$12,635	$9,476	$6,317	$3,159	$0	$0	$0	$0	$0	
6	Average Net Investment				23,690	20,532	17,373	14,214	11,056	7,897	4,738	1,579	0	0	0	0	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		41	36	30	25	19	14	8	3	0	0	0	0	176
	b. Equity Component Grossed Up For Taxes	5.75%	5.71%		114	98	83	68	53	38	23	8	0	0	0	0	485
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.3596%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (B)				3,159	3,159	3,159	3,159	3,159	3,159	3,159	3,159	0	0	0	0	25,270
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009772			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$3,314	$3,293	$3,272	$3,252	$3,231	$3,211	$3,190	$3,170	$0	$0	$0	$0	$25,931
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,314	$3,293	$3,272	$3,252	$3,231	$3,211	$3,190	$3,170	$0	$0	$0	$0	$25,931

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) Investment amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	$0	$0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (B)			137,132	91,425	45,718	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$137,132	$91,425	$45,718	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment				114,279	68,572	22,859	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		199	119	40	0	0	0	0	0	0	0	0	0	358
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		542	325	108	0	0	0	0	0	0	0	0	0	975
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	Blended			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (B)				45,707	45,707	45,718	0	0	0	0	0	0	0	0	0	137,132
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.011630			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)				$46,448	$46,151	$45,866	$0	$0	$0	$0	$0	$0	$0	$0	$0	$138,465
	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				$46,448	$46,151	$45,866	$0	$0	$0	$0	$0	$0	$0	$0	$0	$138,465

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	$1,473,801	
3	Less: Accumulated Depreciation			(425,169)	(428,854)	(432,539)	(436,224)	(439,909)	(443,594)	(447,279)	(450,964)	(454,649)	(458,334)	(462,019)	(465,704)	(469,383)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,048,632	$1,044,947	$1,041,262	$1,037,577	$1,033,892	$1,030,207	$1,026,522	$1,022,837	$1,019,152	$1,015,467	$1,011,782	$1,008,097	$1,004,418	
6	Average Net Investment				1,046,790	1,043,105	1,039,420	1,035,735	1,032,050	1,028,365	1,024,680	1,020,995	1,017,310	1,013,625	1,009,940	1,006,258	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		1,820	1,814	1,808	1,801	1,795	1,788	1,679	1,673	1,667	1,661	1,655	1,649	20,810
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		4,965	4,948	4,930	4,913	4,895	4,878	4,872	4,855	4,837	4,820	4,802	4,785	58,500
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.0000%			3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.00993			1,220	1,220	1,220	1,220	1,220	1,220	1,220	1,220	1,220	1,220	1,220	1,220	14,640
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$11,690	$11,667	$11,643	$11,619	$11,595	$11,571	$11,456	$11,433	$11,409	$11,386	$11,362	$11,339	$138,170
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$11,690	$11,667	$11,643	$11,619	$11,595	$11,571	$11,456	$11,433	$11,409	$11,386	$11,362	$11,339	$138,170

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) Investment amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	$1,661,664	
3	Less: Accumulated Depreciation			(1,163,135)	(1,172,274)	(1,181,413)	(1,190,552)	(1,199,691)	(1,208,830)	(1,217,969)	(1,227,108)	(1,236,247)	(1,245,386)	(1,254,525)	(1,263,664)	(1,272,803)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$498,529	$489,390	$480,251	$471,112	$461,973	$452,834	$443,695	$434,556	$425,417	$416,278	$407,139	$398,000	$388,861	
6	Average Net Investment				493,960	484,821	475,682	466,543	457,404	448,265	439,126	429,987	420,848	411,709	402,570	393,431	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		859	843	827	811	795	780	720	705	690	675	660	645	9,010
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		2,343	2,300	2,256	2,213	2,170	2,126	2,088	2,045	2,001	1,958	1,914	1,871	25,285
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	6.6000%			9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008500			1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	14,124
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$13,518	$13,459	$13,399	$13,340	$13,281	$13,222	$13,124	$13,066	$13,007	$12,949	$12,890	$12,832	$158,087
	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				$13,518	$13,459	$13,399	$13,340	$13,281	$13,222	$13,124	$13,066	$13,007	$12,949	$12,890	$12,832	$158,087

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	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			$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	$178,938	
3	Less: Accumulated Depreciation			(98,489)	(99,205)	(99,921)	(100,637)	(101,353)	(102,069)	(102,785)	(103,501)	(104,217)	(104,933)	(105,649)	(106,365)	(107,081)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$80,449	$79,733	$79,017	$78,301	$77,585	$76,869	$76,153	$75,437	$74,721	$74,005	$73,289	$72,573	$71,857	
6	Average Net Investment				80,091	79,375	78,659	77,943	77,227	76,511	75,795	75,079	74,363	73,647	72,931	72,215	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		139	138	137	136	134	133	124	123	122	121	120	118	1,545
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		380	377	373	370	366	363	360	357	354	350	347	343	4,340
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	4.8000%			716	716	716	716	716	716	716	716	716	716	716	716	8,592
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009420			140	140	140	140	140	140	140	140	140	140	140	140	1,680
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,375	$1,371	$1,366	$1,362	$1,356	$1,352	$1,340	$1,336	$1,332	$1,327	$1,323	$1,317	$16,157
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,375	$1,371	$1,366	$1,362	$1,356	$1,352	$1,340	$1,336	$1,332	$1,327	$1,323	$1,317	$16,157

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	$730,295	
3	Less: Accumulated Depreciation			(242,482)	(244,304)	(246,126)	(247,948)	(249,770)	(251,592)	(253,413)	(255,235)	(257,057)	(258,879)	(260,701)	(262,523)	(264,349)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$487,813	$485,991	$484,169	$482,348	$480,526	$478,704	$476,882	$475,060	$473,238	$471,416	$469,595	$467,773	$465,946	
6	Average Net Investment				486,902	485,080	483,258	481,437	479,615	477,793	475,971	474,149	472,327	470,506	468,684	466,859	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		847	844	840	837	834	831	780	777	774	771	768	765	9,668
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		2,310	2,301	2,292	2,284	2,275	2,266	2,263	2,254	2,246	2,237	2,229	2,220	27,177
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.9936%			1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	21,862
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009930			604	604	604	604	604	604	604	604	604	604	604	604	7,252
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$5,583	$5,571	$5,558	$5,547	$5,535	$5,523	$5,469	$5,457	$5,446	$5,434	$5,423	$5,411	$65,959
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$5,583	$5,571	$5,558	$5,547	$5,535	$5,523	$5,469	$5,457	$5,446	$5,434	$5,423	$5,411	$65,959

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	$1,037,199	
3	Less: Accumulated Depreciation			(392,376)	(395,228)	(398,080)	(400,932)	(403,784)	(406,636)	(409,488)	(412,340)	(415,192)	(418,044)	(420,896)	(423,748)	(426,600)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$644,823	$641,971	$639,119	$636,267	$633,415	$630,563	$627,711	$624,859	$622,007	$619,155	$616,303	$613,451	$610,599	
6	Average Net Investment				643,397	640,545	637,693	634,841	631,989	629,137	626,285	623,433	620,581	617,729	614,877	612,025	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		1,119	1,114	1,109	1,104	1,099	1,094	1,026	1,022	1,017	1,012	1,008	1,003	12,727
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		3,052	3,038	3,025	3,011	2,998	2,984	2,978	2,964	2,951	2,937	2,924	2,910	35,772
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.3000%			2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008670			749	749	749	749	749	749	749	749	749	749	749	749	8,988
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$7,772	$7,753	$7,735	$7,716	$7,698	$7,679	$7,605	$7,587	$7,569	$7,550	$7,533	$7,514	$91,711
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$7,772	$7,753	$7,735	$7,716	$7,698	$7,679	$7,605	$7,587	$7,569	$7,550	$7,533	$7,514	$91,711

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	$3,616,904	
3	Less: Accumulated Depreciation			(822,062)	(829,899)	(837,736)	(845,573)	(853,410)	(861,247)	(869,084)	(876,921)	(884,758)	(892,595)	(900,432)	(908,269)	(916,094)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,794,842	$2,787,005	$2,779,168	$2,771,331	$2,763,494	$2,755,657	$2,747,820	$2,739,983	$2,732,146	$2,724,309	$2,716,472	$2,708,635	$2,700,810	
6	Average Net Investment				2,790,923	2,783,086	2,775,249	2,767,412	2,759,575	2,751,738	2,743,901	2,736,064	2,728,227	2,720,390	2,712,553	2,704,722	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		4,853	4,840	4,826	4,813	4,799	4,785	4,497	4,484	4,471	4,458	4,446	4,433	55,705
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		13,238	13,201	13,164	13,127	13,090	13,052	13,047	13,009	12,972	12,935	12,898	12,860	156,593
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.6000%			$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	$7,837	94,044
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.011630			3,505	3,505	3,505	3,505	3,505	3,505	3,505	3,505	3,505	3,505	3,505	3,505	42,060
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$29,433	$29,383	$29,332	$29,282	$29,231	$29,179	$28,886	$28,835	$28,785	$28,735	$28,686	$28,635	$348,402
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$29,433	$29,383	$29,332	$29,282	$29,231	$29,179	$28,886	$28,835	$28,785	$28,735	$28,686	$28,635	$348,402

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	$141,435	
3	Less: Accumulated Depreciation			(63,234)	(63,475)	(63,716)	(63,957)	(64,198)	(64,439)	(64,680)	(64,921)	(65,162)	(65,403)	(65,644)	(65,885)	(66,126)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$78,201	$77,960	$77,719	$77,478	$77,237	$76,996	$76,755	$76,514	$76,273	$76,032	$75,791	$75,550	$75,309	
6	Average Net Investment				78,080	77,839	77,598	77,357	77,116	76,875	76,634	76,393	76,152	75,911	75,670	75,429	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		136	135	135	135	134	134	126	125	125	124	124	124	1,557
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		370	369	368	367	366	365	364	363	362	361	360	359	4,374
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.0482%			241	241	241	241	241	241	241	241	241	241	241	241	2,892
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.013030			154	154	154	154	154	154	154	154	154	154	154	154	1,848
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$901	$899	$898	$897	$895	$894	$885	$883	$882	$880	$879	$878	$10,671
	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				$901	$899	$898	$897	$895	$894	$885	$883	$882	$880	$879	$878	$10,671

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	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	394,968	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$0	
3	Less: Accumulated Depreciation			(203,712)	(205,489)	(207,266)	(209,043)	(210,820)	(212,597)	(214,374)	(216,151)	(217,928)	(219,705)	(221,482)	(223,259)	0	
3a	Regulatory Asset Balance (B)			0	0	0	0	0	0	0	0	0	0	0	0	169,932	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$191,256	$189,479	$187,702	$185,925	$184,148	$182,371	$180,594	$178,817	$177,040	$175,263	$173,486	$171,709	$169,932	
6	Average Net Investment				190,367	188,590	186,813	185,036	183,259	181,482	179,705	177,928	176,151	174,374	172,597	170,820	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		331	328	325	322	319	316	295	292	289	286	283	280	3,666
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		903	895	886	878	869	861	854	846	838	829	821	812	10,292
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	5.4000%			1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	21,324
	b. Amortization (B)				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009930			327	327	327	327	327	327	327	327	327	327	327	327	3,924
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$3,338	$3,327	$3,315	$3,304	$3,292	$3,281	$3,253	$3,242	$3,231	$3,219	$3,208	$3,196	$39,206
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,338	$3,327	$3,315	$3,304	$3,292	$3,281	$3,253	$3,242	$3,231	$3,219	$3,208	$3,196	$39,206

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	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			$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	$33,092	
3	Less: Accumulated Depreciation			(19,563)	(19,665)	(19,767)	(19,869)	(19,971)	(20,073)	(20,175)	(20,277)	(20,379)	(20,481)	(20,583)	(20,685)	(20,787)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$13,529	$13,427	$13,325	$13,223	$13,121	$13,019	$12,917	$12,815	$12,713	$12,611	$12,509	$12,407	$12,305	
6	Average Net Investment				13,478	13,376	13,274	13,172	13,070	12,968	12,866	12,764	12,662	12,560	12,458	12,356	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		23	23	23	23	23	23	21	21	21	21	20	20	262
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		64	63	63	62	62	62	61	61	60	60	59	59	736
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.7000%			102	102	102	102	102	102	102	102	102	102	102	102	1,224
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.001645			5	5	5	5	5	5	5	5	5	5	5	5	60
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$194	$193	$193	$192	$192	$192	$189	$189	$188	$188	$186	$186	$2,282
	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				$194	$193	$193	$192	$192	$192	$189	$189	$188	$188	$186	$186	$2,282

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	
3	Less: Accumulated Depreciation			10,412	7,482	4,552	1,622	(1,308)	(4,238)	(7,168)	(10,098)	(13,028)	(15,958)	(18,888)	(21,818)	(24,748)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,376,359	$2,373,429	$2,370,499	$2,367,569	$2,364,639	$2,361,709	$2,358,779	$2,355,849	$2,352,919	$2,349,989	$2,347,059	$2,344,129	$2,341,199	
6	Average Net Investment				2,374,894	2,371,964	2,369,034	2,366,104	2,363,174	2,360,244	2,357,314	2,354,384	2,351,454	2,348,524	2,345,594	2,342,664	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		4,130	4,125	4,120	4,115	4,110	4,104	3,863	3,859	3,854	3,849	3,844	3,839	47,812
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		11,265	11,251	11,237	11,223	11,209	11,195	11,209	11,195	11,181	11,167	11,153	11,139	134,424
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.4860%			2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	35,160
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.001645			324	324	324	324	324	324	324	324	324	324	324	324	3,888
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$18,649	$18,630	$18,611	$18,592	$18,573	$18,553	$18,326	$18,308	$18,289	$18,270	$18,251	$18,232	$221,284
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$18,649	$18,630	$18,611	$18,592	$18,573	$18,553	$18,326	$18,308	$18,289	$18,270	$18,251	$18,232	$221,284

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	
3	Less: Accumulated Depreciation			(79,086)	(79,611)	(80,136)	(80,661)	(81,186)	(81,711)	(82,236)	(82,761)	(83,286)	(83,811)	(84,336)	(84,861)	(85,386)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$211,211	$210,686	$210,161	$209,636	$209,111	$208,586	$208,061	$207,536	$207,011	$206,486	$205,961	$205,436	$204,911	
6	Average Net Investment				210,949	210,424	209,899	209,374	208,849	208,324	207,799	207,274	206,749	206,224	205,699	205,174	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		367	366	365	364	363	362	341	340	339	338	337	336	4,218
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		1,001	998	996	993	991	988	988	986	983	981	978	976	11,859
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.1722%			525	525	525	525	525	525	525	525	525	525	525	525	6,300
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008490			205	205	205	205	205	205	205	205	205	205	205	205	2,460
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,098	$2,094	$2,091	$2,087	$2,084	$2,080	$2,059	$2,056	$2,052	$2,049	$2,045	$2,042	$24,837
	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				$2,098	$2,094	$2,091	$2,087	$2,084	$2,080	$2,059	$2,056	$2,052	$2,049	$2,045	$2,042	$24,837

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	$161,754	
3	Less: Accumulated Depreciation			(48,185)	(48,589)	(48,993)	(49,397)	(49,801)	(50,205)	(50,609)	(51,013)	(51,417)	(51,821)	(52,225)	(52,629)	(53,033)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 + 3 + 4)			$113,569	$113,165	$112,761	$112,357	$111,953	$111,549	$111,145	$110,741	$110,337	$109,933	$109,529	$109,125	$108,721	
6	Average Net Investment				113,367	112,963	112,559	112,155	111,751	111,347	110,943	110,539	110,135	109,731	109,327	108,923	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		197	196	196	195	194	194	182	181	181	180	179	179	2,254
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		538	536	534	532	530	528	528	526	524	522	520	518	6,336
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.0000%			404	404	404	404	404	404	404	404	404	404	404	404	4,848
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009420			127	127	127	127	127	127	127	127	127	127	127	127	1,524
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,266	$1,263	$1,261	$1,258	$1,255	$1,253	$1,241	$1,238	$1,236	$1,233	$1,230	$1,228	$14,962
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,266	$1,263	$1,261	$1,258	$1,255	$1,253	$1,241	$1,238	$1,236	$1,233	$1,230	$1,228	$14,962

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	$275,347	
3	Less: Accumulated Depreciation			(58,153)	(58,511)	(58,869)	(59,227)	(59,585)	(59,943)	(60,301)	(60,659)	(61,017)	(61,375)	(61,733)	(62,091)	(62,449)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 + 3 + 4)			$217,194	$216,836	$216,478	$216,120	$215,762	$215,404	$215,046	$214,688	$214,330	$213,972	$213,614	$213,256	$212,898	
6	Average Net Investment				217,015	216,657	216,299	215,941	215,583	215,225	214,867	214,509	214,151	213,793	213,435	213,077	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		377	377	376	376	375	374	352	352	351	350	350	349	4,359
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		1,029	1,028	1,026	1,024	1,023	1,021	1,022	1,020	1,018	1,017	1,015	1,013	12,256
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.5610%			358	358	358	358	358	358	358	358	358	358	358	358	4,296
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009930			228	228	228	228	228	228	228	228	228	228	228	228	2,736
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,992	$1,991	$1,988	$1,986	$1,984	$1,981	$1,960	$1,958	$1,955	$1,953	$1,951	$1,948	$23,647
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,992	$1,991	$1,988	$1,986	$1,984	$1,981	$1,960	$1,958	$1,955	$1,953	$1,951	$1,948	$23,647

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation			(52,479)	(52,863)	(53,247)	(53,631)	(54,015)	(54,399)	(54,783)	(55,167)	(55,551)	(55,935)	(56,319)	(56,703)	(57,087)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 + 3 + 4)			$146,509	$146,125	$145,741	$145,357	$144,973	$144,589	$144,205	$143,821	$143,437	$143,053	$142,669	$142,285	$141,901	
6	Average Net Investment				146,317	145,933	145,549	145,165	144,781	144,397	144,013	143,629	143,245	142,861	142,477	142,093	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		2.09%	1.97%	254	254	253	252	252	251	236	235	235	234	234	233	2,923
	b. Equity Component Grossed Up For Taxes		5.69%	5.71%	694	692	690	689	687	685	685	683	681	679	677	676	8,218
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.3149%			384	384	384	384	384	384	384	384	384	384	384	384	4,608
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009930			165	165	165	165	165	165	165	165	165	165	165	165	1,980
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,497	$1,495	$1,492	$1,490	$1,488	$1,485	$1,470	$1,467	$1,465	$1,462	$1,460	$1,458	$17,729
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,497	$1,495	$1,492	$1,490	$1,488	$1,485	$1,470	$1,467	$1,465	$1,462	$1,460	$1,458	$17,729

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation			(30,027)	(30,246)	(30,465)	(30,684)	(30,903)	(31,122)	(31,341)	(31,560)	(31,779)	(31,998)	(32,217)	(32,436)	(32,655)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Net Investment (Lines 2 + 3 + 4)			$57,640	$57,421	$57,202	$56,983	$56,764	$56,545	$56,326	$56,107	$55,888	$55,669	$55,450	$55,231	$55,012	
6	Average Net Investment				57,531	57,312	57,093	56,874	56,655	56,436	56,217	55,998	55,779	55,560	55,341	55,122	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		2.09%	1.97%	100	100	99	99	99	98	92	92	91	91	91	90	1,142
	b. Equity Component Grossed Up For Taxes		5.69%	5.71%	273	272	271	270	269	268	267	266	265	264	263	262	3,210
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.0000%			219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.011630			85	85	85	85	85	85	85	85	85	85	85	85	1,020
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$677	$676	$674	$673	$672	$670	$663	$662	$660	$659	$658	$656	$8,000
	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				$677	$676	$674	$673	$672	$670	$663	$662	$660	$659	$658	$656	$8,000

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	347,198	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	0	
3	Less: Accumulated Depreciation			(97,245)	(98,084)	(98,923)	(99,762)	(100,601)	(101,440)	(102,279)	(103,118)	(103,957)	(104,796)	(105,635)	(106,474)	0	
3a	Regulatory Asset Balance (B)			0	0	0	0	0	0	0	0	0	0	0	0	239,885	
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)			$249,953	$249,114	$248,275	$247,436	$246,597	$245,758	$244,919	$244,080	$243,241	$242,402	$241,563	$240,724	$239,885	
6	Average Net Investment				249,533	248,694	247,855	247,016	246,177	245,338	244,499	243,660	242,821	241,982	241,143	240,304	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		434	432	431	430	428	427	401	399	398	397	395	394	4,966
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		1,184	1,180	1,176	1,172	1,168	1,164	1,163	1,159	1,155	1,151	1,147	1,143	13,962
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.9000%			839	839	839	839	839	839	839	839	839	839	839	839	10,068
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009930			287	287	287	287	287	287	287	287	287	287	287	287	3,444
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,744	$2,738	$2,733	$2,728	$2,722	$2,717	$2,690	$2,684	$2,679	$2,674	$2,668	$2,663	$32,440
	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				$2,744	$2,738	$2,733	$2,728	$2,722	$2,717	$2,690	$2,684	$2,679	$2,674	$2,668	$2,663	$32,440

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation			(104,455)	(105,242)	(106,029)	(106,816)	(107,603)	(108,390)	(109,177)	(109,964)	(110,751)	(111,538)	(112,325)	(113,112)	(113,899)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$245,129	$244,342	$243,555	$242,768	$241,981	$241,194	$240,407	$239,620	$238,833	$238,046	$237,259	$236,472	$235,685	
6	Average Net Investment				244,735	243,948	243,161	242,374	241,587	240,800	240,013	239,226	238,439	237,652	236,865	236,078	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		426	424	423	421	420	419	393	392	391	389	388	387	4,873
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		1,161	1,157	1,153	1,150	1,146	1,142	1,141	1,137	1,134	1,130	1,126	1,123	13,700
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.7000%			787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008500			248	248	248	248	248	248	248	248	248	248	248	248	2,976
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,622	$2,616	$2,611	$2,606	$2,601	$2,596	$2,569	$2,564	$2,560	$2,554	$2,549	$2,545	$30,993
	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				$2,622	$2,616	$2,611	$2,606	$2,601	$2,596	$2,569	$2,564	$2,560	$2,554	$2,549	$2,545	$30,993

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (B)			9,674	6,450	3,225	(0)	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$9,674	$6,450	$3,225	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment				8,062	4,837	1,612	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		14	8	3	0	0	0	0	0	0	0	0	0	25
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		38	23	8	0	0	0	0	0	0	0	0	0	69
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.2187%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (B)				3,225	3,225	3,225	0	0	0	0	0	0	0	0	0	9,674
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.011630			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$3,277	$3,256	$3,236	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,768
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,277	$3,256	$3,236	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,768

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation			(61,266)	(61,689)	(62,112)	(62,535)	(62,958)	(63,381)	(63,804)	(64,227)	(64,650)	(65,073)	(65,496)	(65,919)	(66,342)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$320,294	$319,871	$319,448	$319,025	$318,602	$318,179	$317,756	$317,333	$316,910	$316,487	$316,064	$315,641	$315,218	
6	Average Net Investment				320,082	319,659	319,236	318,813	318,390	317,967	317,544	317,121	316,698	316,275	315,852	315,429	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		557	556	555	554	554	553	520	520	519	518	518	517	6,441
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		1,518	1,516	1,514	1,512	1,510	1,508	1,510	1,508	1,506	1,504	1,502	1,500	18,108
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.3299%			423	423	423	423	423	423	423	423	423	423	423	423	5,076
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008060			256	256	256	256	256	256	256	256	256	256	256	256	3,072
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,754	$2,751	$2,748	$2,745	$2,743	$2,740	$2,709	$2,707	$2,704	$2,701	$2,699	$2,696	$32,697
	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				$2,754	$2,751	$2,748	$2,745	$2,743	$2,740	$2,709	$2,707	$2,704	$2,701	$2,699	$2,696	$32,697

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) Investment amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River - FGD Common (Project 7.4d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	
3	Less: Accumulated Depreciation			(182,129)	(186,553)	(190,977)	(195,401)	(199,825)	(204,249)	(208,673)	(213,097)	(217,521)	(221,945)	(226,369)	(230,793)	(235,217)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,966,971	$1,962,547	$1,958,123	$1,953,699	$1,949,275	$1,944,851	$1,940,427	$1,936,003	$1,931,579	$1,927,155	$1,922,731	$1,918,307	$1,913,883	
6	Average Net Investment				1,964,759	1,960,335	1,955,911	1,951,487	1,947,063	1,942,639	1,938,215	1,933,791	1,929,367	1,924,943	1,920,519	1,916,095	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		3,417	3,409	3,401	3,394	3,386	3,378	3,177	3,169	3,162	3,155	3,148	3,140	39,336
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		9,319	9,299	9,278	9,257	9,236	9,215	9,216	9,195	9,174	9,153	9,132	9,111	110,585
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.4700%			4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.001703			305	305	305	305	305	305	305	305	305	305	305	305	3,660
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$17,465	$17,437	$17,408	$17,380	$17,351	$17,322	$17,122	$17,093	$17,065	$17,037	$17,009	$16,980	$206,669
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$17,465	$17,437	$17,408	$17,380	$17,351	$17,322	$17,122	$17,093	$17,065	$17,037	$17,009	$16,980	$206,669

For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$1,371,979	$1,237,479	$974,639	$579,883	$225,674	$708,445	$408,167	$77,771	$262,092	$99,698	($108,285)	($98,859)	$5,738,684
	b. Clearings to Plant				0	79,482,748	974,639	579,883	225,674	708,445	408,167	77,771	262,092	99,698	(108,285)	(98,859)	
	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			$614,010	614,010	80,096,758	81,071,397	81,651,280	81,876,954	82,585,399	82,993,566	83,071,337	83,333,429	83,433,127	83,324,842	83,225,983	
3	Less: Accumulated Depreciation			(43,163)	(43,923)	(143,109)	(243,502)	(344,614)	(446,005)	(548,273)	(651,047)	(753,917)	(857,112)	(960,430)	(1,063,614)	(1,166,676)	
4	CWIP - Non-Interest Bearing			76,873,290	78,245,269	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$77,444,137	$78,815,356	$79,953,649	$80,827,895	$81,306,666	$81,430,949	$82,037,126	$82,342,519	$82,317,420	$82,476,317	$82,472,697	$82,261,228	$82,059,307	
6	Average Net Investment				78,129,746	79,384,502	80,390,772	81,067,280	81,368,807	81,734,038	82,189,823	82,329,970	82,396,869	82,474,507	82,366,963	82,160,268	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		135,868	138,050	139,800	140,976	141,500	142,135	134,702	134,932	135,042	135,169	134,993	134,654	1,647,821
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		370,595	376,546	381,320	384,528	385,959	387,691	390,797	391,463	391,781	392,150	391,639	390,656	4,635,125
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.4860%			760	99,186	100,393	101,112	101,391	102,268	102,774	102,870	103,195	103,318	103,184	103,062	1,123,513
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.001703			87	11,366	11,505	11,587	11,619	11,720	11,777	11,789	11,826	11,840	11,824	11,810	128,750
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$507,310	$625,148	$633,018	$638,203	$640,469	$643,814	$640,050	$641,054	$641,844	$642,477	$641,640	$640,182	$7,535,209
	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				$507,310	$625,148	$633,018	$638,203	$640,469	$643,814	$640,050	$641,054	$641,844	$642,477	$641,640	$640,182	$7,535,209

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2019 through December 2019
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River - FGD Common (Project 7.4r) - CR4 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	
3	Less: Accumulated Depreciation			(87,865)	(89,226)	(90,587)	(91,948)	(93,309)	(94,670)	(96,031)	(97,392)	(98,753)	(100,114)	(101,475)	(102,836)	(104,197)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$573,133	$571,772	$570,411	$569,050	$567,689	$566,328	$564,967	$563,606	$562,245	$560,884	$559,523	$558,162	$556,801	
6	Average Net Investment				572,453	571,092	569,731	568,370	567,009	565,648	564,287	562,926	561,565	560,204	558,843	557,482	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		995	993	991	988	986	984	925	923	920	918	916	914	11,453
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		2,715	2,709	2,702	2,696	2,690	2,683	2,683	2,677	2,670	2,664	2,657	2,651	32,197
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.4700%			1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	16,332
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.001703			94	94	94	94	94	94	94	94	94	94	94	94	1,128
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$5,165	$5,157	$5,148	$5,139	$5,131	$5,122	$5,063	$5,055	$5,045	$5,037	$5,028	$5,020	$61,110
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$5,165	$5,157	$5,148	$5,139	$5,131	$5,122	$5,063	$5,055	$5,045	$5,037	$5,028	$5,020	$61,110

For Project: CAIR Crystal River - FGD Common (Project 7.4s) - CR5 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-19	Actual Feb-19	Actual Mar-19	Actual Apr-19	Actual May-19	Actual Jun-19	Actual Jul-19	Actual Aug-19	Actual Sep-19	Actual Oct-19	Actual Nov-19	Actual Dec-19	Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	
3	Less: Accumulated Depreciation			(54,331)	(55,372)	(56,413)	(57,454)	(58,495)	(59,536)	(60,577)	(61,618)	(62,659)	(63,700)	(64,741)	(65,782)	(66,823)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$451,573	$450,532	$449,491	$448,450	$447,409	$446,368	$445,327	$444,286	$443,245	$442,204	$441,163	$440,122	$439,081	
6	Return on Average Net Investment (A)				451,053	450,012	448,971	447,930	446,889	445,848	444,807	443,766	442,725	441,684	440,643	439,602	
7	Return on Average Net Investment	Jan-Jun	Jul-Dec														
	a. Debt Component	2.09%	1.97%		784	783	781	779	777	775	729	727	726	724	722	720	9,027
	b. Equity Component Grossed Up For Taxes	5.69%	5.71%		2,139	2,135	2,130	2,125	2,120	2,115	2,115	2,110	2,105	2,100	2,095	2,090	25,379
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.4700%			1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	12,492
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.001703			72	72	72	72	72	72	72	72	72	72	72	72	864
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$4,036	$4,031	$4,024	$4,017	$4,010	$4,003	$3,957	$3,950	$3,944	$3,937	$3,930	$3,923	$47,762
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$4,036	$4,031	$4,024	$4,017	$4,010	$4,003	$3,957	$3,950	$3,944	$3,937	$3,930	$3,923	$47,762

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Commission Forms 42-1E Through 42-9E

January 2020 - December 2020
Calculation for the Current Period Actual / Estimated Amount
Actuals for the Period January 2020 - June 2020
Estimates for the Period July 2020 - December 2020

Docket No. 20200007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 23
PARTY: CAM-3
DESCRIPTION: Forms 42-1E – 42-9EJanuary 2020 – December 2020

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period (Form 42-2E, Line 5)	$ 8,011,775
2	Interest Provision (Form 42-2E, Line 6)	85,404
3	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2020 to December 2020 (Lines 1 + 2 + 3)	$ 8,097,179

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$2,043,276	$2,053,327	$2,175,236	$2,506,103	$2,306,710	$2,665,667	$3,266,583	$3,280,780	$3,322,685	$3,039,464	$2,495,019	$2,378,231	$31,533,079
2	True-Up Provision (Order No. PSC-2019-0500-FOF-EI)	18,654,948	1,554,579	1,554,579	1,554,579	1,554,579	1,554,579	1,554,579	1,554,579	1,554,579	1,554,579	1,554,579	1,554,579	1,554,579	18,654,948
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		$3,597,855	3,607,906	3,729,815	4,060,682	3,861,289	4,220,246	4,821,162	4,835,359	4,877,264	4,594,043	4,049,598	3,932,810	50,188,028
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5E, Line 9)		$1,169,339	902,941	1,470,579	1,127,642	1,473,241	924,838	2,225,100	1,828,905	1,513,590	1,574,714	1,261,659	2,050,831	17,523,379
	b. Capital Investment Projects (Form 42-7E, Line 9)		1,788,272	2,118,734	2,082,431	2,092,821	2,047,566	2,044,564	2,048,447	2,056,485	2,073,732	2,084,951	2,115,067	2,099,803	24,652,874
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Total Jurisdictional ECRC Costs		$2,957,611	$3,021,675	$3,553,010	$3,220,463	$3,520,807	$2,969,402	$4,273,547	$3,885,390	$3,587,322	$3,659,665	$3,376,726	$4,150,634	$42,176,253
5	Over/(Under) Recovery (Line 3 - Line 4d)		$640,244	586,231	176,805	840,219	340,482	1,250,844	547,614	949,968	1,289,942	934,378	672,872	(217,824)	$8,011,775
6	Interest Provision (Form 42-3E, Line 10)		22,967	20,598	22,505	12,645	742	928	985	913	874	834	766	647	85,404
7	Beginning Balance True-Up & Interest Provision		18,654,948	17,763,580	16,815,830	15,460,562	14,758,846	13,545,491	13,242,684	12,236,704	11,633,006	11,369,243	10,749,876	9,868,935	18,654,948
	a. Deferred True-Up - January 2019 to December 2019 (2019 TU filing dated April 1, 2020)		(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)	(1,792,439)
8	True-Up Collected/(Refunded) (Line 2)		(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(1,554,579)	(18,654,948)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		$15,971,141	15,023,391	13,668,122	12,966,407	11,753,052	11,450,244	10,444,265	9,840,567	9,576,804	8,957,436	8,076,496	6,304,739	$6,304,739
10	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up (Over/(Under) (Lines 9 + 10)		$15,971,141	$15,023,391	$13,668,122	$12,966,407	$11,753,052	$11,450,244	10,444,265	$9,840,567	$9,576,804	$8,957,436	$8,076,496	$6,304,739	$6,304,739

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Interest Provision
(in Dollars)

Line	Description	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$16,862,509	$15,971,141	$15,023,391	$13,668,122	$12,966,407	$11,753,052	$11,450,244	$10,444,265	$9,840,567	$9,576,804	$8,957,436	$8,076,496	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	15,948,174	15,002,793	13,645,617	12,953,762	11,752,310	11,449,316	10,443,280	9,839,654	9,575,930	8,956,602	8,075,730	6,304,092	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	32,810,683	30,973,934	28,669,008	26,621,884	24,718,716	23,202,368	21,893,524	20,283,919	19,416,497	18,533,406	17,033,166	14,380,588	
4	Average True-Up Amount (Line 3 x 1/2)	16,405,342	15,486,967	14,334,504	13,310,942	12,359,358	11,601,184	10,946,762	10,141,960	9,708,249	9,266,703	8,516,583	7,190,294	
5	Interest Rate (Last Business Day of Prior Month)	1.71%	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	
6	Interest Rate (Last Business Day of Current Month)	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.35%	3.20%	3.77%	2.27%	0.14%	0.19%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	
8	Average Interest Rate (Line 7 x 1/2)	1.675%	1.600%	1.885%	1.135%	0.070%	0.095%	0.110%	0.110%	0.110%	0.110%	0.110%	0.110%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.140%	0.133%	0.157%	0.095%	0.006%	0.008%	0.009%	0.009%	0.009%	0.009%	0.009%	0.009%	
10	Interest Provision for the Month (Line 4 x Line 9)	$22,967	$20,598	$22,505	$12,645	$742	$928	$985	$913	$874	$834	$766	$647	85,404

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Variance Report of O&M Activities
(In Dollars)

Line		Description	(1) Actual / Estimated	(2) Projection Filing	(3) Variance Amount	(4) Variance Percent
1		O&M Activities - System				
	1	Transmission Substation Environmental Investigation, Remediation and Pollution Prevention	$12,640	$24,996	($12,356)	-49%
	1a	Distribution Substation Environmental Investigation, Remediation and Pollution Prevention	157	0	157	100%
	2	Distribution System Environmental Investigation, Remediation and Pollution Prevention	0	0	0	0%
	3	Pipeline Integrity Management - Bartow /Anclote Pipeline - Intm	0	0	0	0%
	4	Above Ground Tank Secondary Containment	0	0	0	0%
	5	SO2/NOx Emissions Allowances - Energy	3,470	14,722	(11,252)	-76%
	6	Phase II Cooling Water Intake 316(b) - Base	156,740	68,200	88,540	130%
	6.a	Phase II Cooling Water Intake 316(b) - Intm	148,387	67,600	80,787	120%
	7.2	CAIR/CAMR - Peaking	0	0	0	0%
	7.4	CAIR/CAMR Crystal River - Base	10,946,197	13,978,392	(3,032,195)	-22%
	7.4	CAIR/CAMR Crystal River - Energy	4,253,088	5,669,608	(1,416,520)	-25%
	7.4	CAIR/CAMR Crystal River - A&G	68,946	96,825	(27,879)	-29%
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	983,194	2,900,000	(1,916,806)	-66%
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0%
	8	Arsenic Groundwater Standard - Base	1,234,899	1,267,500	(32,601)	-3%
	9	Sea Turtle - Coastal Street Lighting - Distrib	0	300	(300)	-100%
	11	Modular Cooling Towers - Base	0	0	0	0%
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0%
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0%
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0%
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0%
	15.1	Effluent Limitation Guidelines Program CRN - Energy	0	40,000	(40,000)	-100%
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	29,840	25,400	4,440	17%
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	121,543	598,000	(476,457)	-80%
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0%
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0%
	18	Coal Combustion Residual (CCR) Rule - Energy	917,228	240,900	676,328	281%
2		Total O&M Activities - Recoverable Costs	$18,876,329	$24,992,444	($6,116,115)	-24%
3		Recoverable Costs Allocated to Energy	6,308,363	9,488,631	(3,180,268)	-34%
4		Recoverable Costs Allocated to Demand	$12,567,966	$15,503,813	($2,935,847)	-19%

Notes:

Column (1) End of Period Totals on Form 42-5E
Column (2) 2020 Projection Filing Form 42-2P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

O&M Activities
(in Dollars)

Line		Description	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1		O&M Activities - System													
	1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$1,296	$1,105	($374)	$308	$649	$338	$2,319	$1,000	$2,000	$1,000	$1,000	$2,000	$12,640
	1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	0	0	374	0	(217)	0	0	0	0	0	0	0	157
	2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	Above Ground Tank Secondary Containment - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	SO2/NOx Emissions Allowances - Energy	261	212	9	(1,999)	0	(47)	331	823	714	839	1,027	1,300	3,470
	6	Phase II Cooling Water Intake 316(b) - Base	27,135	26,151	4,746	2,053	77,067	13,988	0	5,200	0	200	0	200	156,740
	6a	Phase II Cooling Water Intake 316(b) - Intm	16,471	20,958	18,535	102,551	(24,211)	8,783	0	5,100	0	100	0	100	148,387
	7.2	CAIR/CAMR - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River - Base	1,105,292	736,840	1,254,794	861,583	970,700	816,988	1,000,000	800,000	800,000	800,000	800,000	1,000,000	10,946,197
	7.4	CAIR/CAMR Crystal River - Energy	(3,673)	0	41,720	112,935	365,231	325,023	543,512	742,992	609,382	622,674	402,482	490,810	4,253,088
	7.4	CAIR/CAMR Crystal River - A&G	3,425	5,372	7,259	6,025	6,053	4,511	6,050	6,050	6,050	6,050	6,050	6,050	68,946
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	56,978	29,604	12,134	46,552	83,072	54,855	150,000	150,000	100,000	100,000	100,000	100,000	983,194
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	8	Arsenic Groundwater Standard - Base	1,640	4,843	14,781	28,599	16,036	0	539,500	52,000	37,500	0	0	540,000	1,234,899
	9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
	11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15.1	Effluent Limitation Guidelines Program CRN - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	623	(7,733)	0	0	4,691	0	11,200	9,860	0	11,200	0	0	29,840
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	0	0	5,666	25,876	0	0	15,000	15,000	15,000	15,000	15,000	15,000	121,543
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	18	Coal Combustion Residual (CCR) Rule - Energy	48,182	151,265	222,440	45,648	89,889	(224,212)	139,200	192,013	56,202	136,700	17,700	42,200	917,228
2		Total O&M Activities - Recoverable Costs	$1,257,630	$968,617	$1,582,085	$1,230,130	$1,588,960	$1,000,227	$2,407,112	$1,980,038	$1,626,848	$1,693,763	$1,343,259	$2,197,659	$18,876,329
3		Recoverable Costs Allocated to Energy	102,371	173,348	281,970	229,011	542,883	155,620	859,243	1,110,688	781,298	886,413	536,209	649,309	6,308,363
4		Recoverable Costs Allocated to Demand - Transm	1,296	1,105	(374)	308	649	338	2,319	1,000	2,000	1,000	1,000	2,000	12,640
		Recoverable Costs Allocated to Demand - Distrib	0	0	374	0	(217)	0	0	0	0	0	0	0	157
		Recoverable Costs Allocated to Demand - Prod-Base	1,134,067	767,834	1,274,321	892,235	1,063,803	830,976	1,539,500	857,200	837,500	800,200	800,000	1,540,200	12,337,836
		Recoverable Costs Allocated to Demand - Prod-Intm	16,471	20,958	18,535	102,551	(24,211)	8,783	0	5,100	0	100	0	100	148,387
		Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
		Recoverable Costs Allocated to Demand - A&G	3,425	5,372	7,259	6,025	6,053	4,511	6,050	6,050	6,050	6,050	6,050	6,050	68,946
5		Retail Energy Jurisdictional Factor	0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.91693	0.92073	0.93259	0.93075	0.95529	0.94423	
6		Retail Transmission Demand Jurisdictional Factor	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	
		Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
		Retail Production Demand Jurisdictional Factor - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
		Retail Production Demand Jurisdictional Factor - Intm	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
		Retail Production Demand Jurisdictional Factor - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
		Retail Production Demand Jurisdictional Factor - A&G	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	
7		Jurisdictional Energy Recoverable Costs (A)	99,884	168,719	266,574	218,500	496,846	142,159	787,867	1,022,645	728,634	825,033	512,237	613,099	5,882,197
8		Jurisdictional Demand Recoverable Costs - Transm (B)	909	775	(263)	216	456	237	1,628	702	1,404	702	702	1,404	8,872
		Jurisdictional Demand Recoverable Costs - Distrib (B)	0	0	372	0	(216)	0	0	0	0	0	0	0	156
		Jurisdictional Demand Recoverable Costs - Prod-Base (B)	1,053,378	713,202	1,183,653	828,753	988,114	771,852	1,429,965	796,210	777,912	743,266	743,080	1,430,615	11,460,000
		Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	11,975	15,237	13,476	74,557	(17,602)	6,385	0	3,708	0	73	0	73	107,882
		Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
		Jurisdictional Demand Recoverable Costs - A&G (B)	3,193	5,008	6,767	5,616	5,643	4,205	5,640	5,640	5,640	5,640	5,640	5,640	64,272
9		Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8)	$1,169,339	$902,941	$1,470,579	$1,127,642	$1,473,241	$924,838	$2,225,100	$1,828,905	$1,513,590	$1,574,714	$1,261,659	$2,050,831	$17,523,379

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Variance Report of Capital Investment Activities
(in Dollars)

Line		Description	(1) Actual / Estimated	(2) Projection Filing	(3) Variance Amount	(4) Variance Percent
1		Capital Investment Activities - System				
	3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline	$0	$0	$0	0%
	4.x	Above Ground Tank Secondary Containment	1,199,345	1,182,244	17,101	1%
	5	SO2/NOx Emissions Allowances	247,445	248,770	(1,325)	-1%
	6	Phase II Cooling Water Intake 316(b) - Base	693,553	653,808	39,745	6%
	7.x	CAIR/CAMR	8,264,611	8,449,943	(185,332)	-2%
	9	Sea Turtle - Coastal Street Lighting	955	1,062	(107)	-10%
	10.x	Underground Storage Tanks	20,543	20,646	(103)	-1%
	11	Modular Cooling Towers	0	0	0	0%
	11.1	Crystal River Thermal Discharge Compliance Project	0	0	0	0%
	15.1	Effluent Limitation Guidelines CRN (ELG)	242,978	229,869	13,109	6%
	16	National Pollutant Discharge Elimination System (NPDES)	1,318,202	1,366,968	(48,766)	-4%
	17x	Mercury & Air Toxics Standards (MATS)	14,573,654	15,280,123	(706,469)	-5%
	18	Coal Combustion Residual (CCR) Rule	63,447	45,451	17,996	40%
2		Total Capital Investment Activities - Recoverable Costs	$26,624,734	$27,478,884	($854,151)	-3%
3		Recoverable Costs Allocated to Energy	$14,864,768	$15,605,464	($740,697)	-5%
4		Recoverable Costs Allocated to Demand	$11,759,966	$11,873,420	($113,454)	-1%

Notes:

Column (1) End of Period Totals on Form 42-7E
Column (2) 2020 Projection Filing Form 42-3P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investment Projects - System (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.1	Above Ground Tank Secondary Containment - Peaking	64,541	81,264	81,003	80,744	80,486	80,229	79,923	79,664	79,404	83,748	83,460	83,171	957,637
4.2	Above Ground Tank Secondary Containment - Base	17,686	18,380	18,360	18,341	18,320	18,302	18,262	18,241	18,222	18,204	18,184	18,165	218,667
4.3	Above Ground Tank Secondary Containment - Intermediate	1,399	1,986	1,982	1,979	1,975	1,972	1,967	1,963	1,960	1,956	1,953	1,949	23,041
5	SO2/NOX Emissions Allowances - Energy	20,634	20,633	20,633	20,639	20,645	20,645	20,614	20,611	20,606	20,601	20,596	20,588	247,445
6	Phase II Cooling Water Intake 316(b) - Base	39,947	44,336	46,728	49,034	51,191	53,660	58,456	64,379	68,568	71,587	72,682	72,985	693,553
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	29,902	31,736	31,590	31,446	31,302	31,159	31,003	30,861	30,714	38,788	38,591	38,394	395,491
7.3	CAMR Crystal River - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
7.4	CAIR/CAMR Crystal River AFUDC - Base	640,701	657,101	656,393	655,690	654,984	654,281	652,807	652,105	651,401	650,698	649,997	649,294	7,825,452
7.4	CAIR/CAMR Crystal River AFUDC - Energy	7,295	3,493	3,477	3,506	3,170	2,953	3,212	3,313	3,313	3,313	3,313	3,313	43,669
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Sea Turtle - Coastal Street Lighting -Distribution	60	82	82	82	82	82	81	81	81	81	81	80	955
10.1	Underground Storage Tanks - Base	1,294	1,178	1,175	1,174	1,171	1,170	1,167	1,165	1,163	1,162	1,159	1,158	14,136
10.2	Underground Storage Tanks - Intermediate	447	548	547	546	544	543	542	541	539	538	537	535	6,407
11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
11.1	Crystal River Thermal Discharge Compliance Project - Base (Post 2012)	0	0	0	0	0	0	0	0	0	0	0	0	0
11.1	Crystal River Thermal Discharge Compliance Project - Base (2012)	0	0	0	0	0	0	0	0	0	0	0	0	0
15.1	Effluent Limitation Guidelines CRN (ELG) - Base	15,621	15,839	16,029	16,390	22,321	22,478	22,470	22,436	22,401	22,366	22,331	22,296	242,978
16	National Pollutant Discharge Elimination System (NPDES) - Intermediate	94,393	112,447	112,220	111,991	111,763	111,535	111,212	110,983	110,756	110,528	110,301	110,073	1,318,202
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	25,770	27,465	27,423	27,381	27,338	27,297	27,225	27,182	27,140	27,099	27,056	27,014	325,393
17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	760,385	1,041,223	1,039,673	1,038,124	1,036,573	1,035,024	1,032,426	1,030,878	1,029,330	1,027,783	1,026,235	1,024,687	12,122,336
17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	169,976	180,140	179,692	179,245	178,798	178,350	177,736	177,290	176,843	176,396	175,950	175,504	2,125,925
18	Coal Combustion Residual (CCR) Rule - Base	3,384	3,541	3,536	3,530	3,526	3,521	3,512	4,363	6,071	7,779	9,488	11,196	63,447
2	Total Investment Projects - Recoverable Costs	$1,893,436	$2,241,392	$2,240,543	$2,239,843	$2,244,190	$2,243,202	$2,242,616	$2,246,056	$2,248,512	$2,262,627	$2,261,914	$2,260,402	$26,624,734
3	Recoverable Costs Allocated to Energy	984,060	1,272,954	1,270,898	1,268,895	1,266,525	1,264,269	1,261,213	1,259,274	1,257,232	1,255,192	1,253,150	1,251,106	14,864,768
	Recoverable Costs Allocated to Distribution Demand	60	82	82	82	82	82	81	81	81	81	81	80	955
4	Recoverable Costs Allocated to Demand - Production - Base	718,633	740,375	742,221	744,159	751,513	753,412	756,674	762,689	767,826	771,796	773,841	775,094	9,058,233
	Recoverable Costs Allocated to Demand - Production - Intermediate	96,239	114,981	114,749	114,516	114,282	114,050	113,721	113,487	113,255	113,022	112,791	112,557	1,347,650
	Recoverable Costs Allocated to Demand - Production - Peaking	94,443	113,000	112,593	112,190	111,788	111,388	110,926	110,525	110,118	122,537	122,052	121,566	1,353,128
5	Retail Energy Jurisdictional Factor	0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.91693	0.92073	0.93259	0.93075	0.95529	0.94423	
	Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
6	Retail Demand Jurisdictional Factor - Production - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
7	Jurisdictional Energy Recoverable Costs (B)	960,148	1,238,966	1,201,507	1,210,653	1,159,123	1,154,910	1,156,447	1,159,452	1,172,486	1,168,275	1,197,125	1,181,335	13,960,427
	Jurisdictional Demand Recoverable Costs - Distribution (B)	60	82	82	82	82	82	81	81	81	81	81	80	951
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	667,502	687,697	689,412	691,212	698,043	699,807	702,837	708,424	713,195	716,883	718,782	719,946	8,413,740
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	69,969	83,595	83,426	83,257	83,086	82,918	82,679	82,508	82,340	82,170	82,002	81,832	979,782
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	90,594	108,394	108,004	107,617	107,232	106,848	106,405	106,020	105,630	117,542	117,077	116,611	1,297,974
9	Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8)	$1,788,272	$2,118,734	$2,082,431	$2,092,821	$2,047,566	$2,044,564	$2,048,447	$2,056,485	$2,073,732	$2,084,951	$2,115,067	$2,099,803	$24,652,874

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9; Form 42-8E, Line 5 for Projects 5 - Emission Allowances and Project 7. 4 - Reagents.
(B) Line 3 x Line 5
(C) Line 4 x Line 6

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Peaking (Project 4.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	178,938	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (A)			$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,840,236	$8,661,298	$8,661,298	$8,661,298	$8,661,298	
3	Less: Accumulated Depreciation			(3,522,436)	(3,548,728)	(3,575,020)	(3,601,312)	(3,627,604)	(3,653,896)	(3,680,188)	(3,706,480)	(3,732,772)	(3,580,126)	(3,671,115)	(3,696,691)	(3,722,267)	
3a	Regulatory Asset Balance (G)			169,932	155,771	141,610	127,449	113,288	99,127	84,966	70,805	56,644	42,483	88,284	68,672	49,060	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$5,487,731	$5,447,279	$5,406,826	$5,366,373	$5,325,920	$5,285,467	$5,245,014	$5,204,561	$5,164,108	$5,123,655	$5,078,467	$5,033,279	$4,988,091	
6	Average Net Investment				$5,467,505	$5,427,052	$5,386,599	$5,346,146	$5,305,693	$5,265,240	$5,224,787	$5,184,334	$5,143,881	$5,101,061	$5,055,873	$5,010,685	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		8,960	8,895	8,827	8,761	8,696	8,629	8,234	8,171	8,106	8,040	7,968	7,896	101,183
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		25,997	25,805	25,612	25,419	25,226	25,036	25,125	24,929	24,734	24,528	24,312	24,095	300,818
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				26,292	26,292	26,292	26,292	26,292	26,292	26,292	26,292	26,292	25,576	25,576	25,576	313,356
	b. Amortization (G)				14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	19,612	19,612	19,612	186,285
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				(10,869)	6,111	6,111	6,111	6,111	6,111	6,111	6,111	6,111	5,992	5,992	5,992	55,995
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$64,541	$81,264	$81,003	$80,744	$80,486	$80,229	$79,923	$79,664	$79,404	$83,748	$83,460	$83,171	957,637
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				64,541	81,264	81,003	80,744	80,486	80,229	79,923	79,664	79,404	83,748	83,460	83,171	957,637
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)				0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				61,911	77,952	77,701	77,453	77,205	76,959	76,665	76,417	76,167	80,334	80,058	79,781	918,604
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$61,911	$77,952	$77,701	$77,453	$77,205	$76,959	$76,665	$76,417	$76,167	$80,334	$80,058	$79,781	$918,604

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.

(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost. January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

(G) Project 4.1a (Turner AST) amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI. Project 4.1i (Higgins) and Project 4.1d (Avon Park) amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	33,092	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$2,399,039	2,399,039	2,399,039	2,399,039	2,399,039	2,399,039	2,399,039	2,399,039	2,399,039	2,399,039	2,399,039	2,399,039	2,365,947	
3	Less: Accumulated Depreciation			($45,535)	(48,567)	(51,599)	(54,631)	(57,663)	(60,695)	(63,727)	(66,759)	(69,791)	(72,823)	(75,855)	(78,887)	(81,919)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,353,504	$2,350,472	$2,347,440	$2,344,408	$2,341,376	$2,338,344	$2,335,312	$2,332,280	$2,329,248	$2,326,216	$2,323,184	$2,320,152	$2,284,028	
6	Average Net Investment				$2,351,988	$2,348,956	$2,345,924	$2,342,892	$2,339,860	$2,336,828	$2,333,796	$2,330,764	$2,327,732	$2,324,700	$2,321,668	$2,302,090	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		3,855	3,850	3,845	3,840	3,834	3,830	3,678	3,673	3,668	3,664	3,659	3,654	45,050
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		11,183	11,169	11,154	11,140	11,125	11,111	11,223	11,207	11,193	11,179	11,164	11,150	133,998
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	3,032	36,384
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				(384)	329	329	329	329	329	329	329	329	329	329	329	3,235
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$17,686	$18,380	$18,360	$18,341	$18,320	$18,302	$18,262	$18,241	$18,222	$18,204	$18,184	$18,165	218,667
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				17,686	18,380	18,360	18,341	18,320	18,302	18,262	18,241	18,222	18,204	18,184	18,165	218,667
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				16,427	17,072	17,054	17,036	17,017	17,000	16,963	16,943	16,926	16,909	16,890	16,873	203,109
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$16,427	$17,072	$17,054	$17,036	$17,017	$17,000	$16,963	$16,943	$16,926	$16,909	$16,890	$16,873	$203,109

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.

(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost. January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation			(85,386)	(85,911)	(86,436)	(86,961)	(87,486)	(88,011)	(88,536)	(89,061)	(89,586)	(90,111)	(90,636)	(91,161)	(91,686)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)			$204,911	$204,386	$203,861	$203,336	$202,811	$202,286	$201,761	$201,236	$200,711	$200,186	$199,661	$199,136	$198,611	
6	Average Net Investment				$204,649	$204,124	$203,599	$203,074	$202,549	$202,024	$201,499	$200,974	$200,449	$199,924	$199,399	$198,874	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		335	335	334	333	332	331	318	317	316	315	314	313	3,893
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		973	971	968	966	963	961	969	966	964	961	959	956	11,577
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)			525	525	525	525	525	525	525	525	525	525	525	525	525	6,300
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			(434)	155	155	155	155	155	155	155	155	155	155	155	155	1,271
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,399	$1,986	$1,982	$1,979	$1,975	$1,972	$1,967	$1,963	$1,960	$1,956	$1,953	$1,949	23,041	
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. Recoverable Costs Allocated to Demand			1,399	1,986	1,982	1,979	1,975	1,972	1,967	1,963	1,960	1,956	1,953	1,949	23,041	
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			1,017	1,444	1,441	1,439	1,436	1,434	1,430	1,427	1,425	1,422	1,420	1,417	16,751	
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,017	$1,444	$1,441	$1,439	$1,436	$1,434	$1,430	$1,427	$1,425	$1,422	$1,420	$1,417	$16,751	

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.

(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost. January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0158150 SO_2 Emission Allowance Inventory			$3,227,480	$3,227,222	$3,227,010	$3,227,001	$3,229,000	$3,229,000	$3,229,000	$3,228,623	$3,227,753	$3,226,992	$3,226,106	$3,225,032	$3,223,685	$3,223,685
	b. 0254020 Auctioned SO_2 Allowance			0	0	0	0	0	(47)	0	47	94	140	187	234	281	281
	c. 0158170 NOx Emission Allowance Inventory			0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Working Capital			$3,227,480	$3,227,222	$3,227,010	$3,227,001	$3,229,000	$3,228,953	$3,229,000	$3,228,670	$3,227,846	$3,227,132	$3,226,293	$3,225,265	$3,223,966	$3,223,966
3	Average Net Investment				$3,227,351	$3,227,116	$3,227,005	$3,228,001	$3,228,977	$3,228,977	$3,228,835	$3,228,258	$3,227,489	$3,226,712	$3,225,779	$3,224,616	
4	Return on Average Net Working Capital Balance (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		5,289	5,289	5,289	5,290	5,292	5,292	5,088	5,087	5,086	5,085	5,084	5,082	62,253
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		15,345	15,344	15,344	15,349	15,353	15,353	15,526	15,524	15,520	15,516	15,512	15,506	185,192
5	Total Return Component (C)				$20,634	$20,633	$20,633	$20,639	$20,645	$20,645	$20,614	$20,611	$20,606	$20,601	$20,596	$20,588	247,445
6	Expense Dr (Cr)																
	a. 0509030 SO_2 Allowance Expense				$261	$212	$9	($1,999)	$0	$0	$377	$870	$761	$886	$1,074	$1,346	3,797
	b. 0407426 Amortization Expense				0	0	0	0	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(327)
	c. 0509212 NOx Allowance Expense				0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (D)				261	212	9	(1,999)	0	(47)	331	823	714	839	1,027	1,300	3,470
8	Total System Recoverable Expenses (Lines 5 + 7)				$20,895	$20,845	$20,642	$18,640	$20,645	$20,598	$20,945	$21,434	$21,320	$21,440	$21,623	$21,888	250,915
	a. Recoverable Costs Allocated to Energy				20,895	20,845	20,642	18,640	20,645	20,598	20,945	21,434	21,320	21,440	21,623	21,888	250,915
	b. Recoverable Costs Allocated to Demand				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor				0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.91693	0.92073	0.93259	0.93075	0.95529	0.94423	
10	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (E)				$20,387	$20,288	$19,515	$17,784	$18,894	$18,816	$19,205	$19,735	$19,883	$19,955	$20,657	$20,667	235,787
12	Retail Demand-Related Recoverable Costs (F)				0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)				$ 20,387	$ 20,288	$ 19,515	$ 17,784	$ 18,894	$ 18,816	$ 19,205	$ 19,735	$ 19,883	$ 19,955	$ 20,657	$ 20,667	$ 235,787

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 5 is reported on Capital Schedule

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

(E) Line 8a x Line 9

(F) Line 8b x Line 10

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Base (Project 6)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$1,112,889	$260,143	$488,106	$233,259	$441,164	$331,194	$1,195,322	$659,852	$652,654	$292,954	$50,354	$44,354	$5,762,245
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation			$0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing			$5,691,363	6,804,252	7,064,395	7,552,501	7,785,760	8,226,924	8,558,118	9,753,440	10,413,292	11,065,946	11,358,900	11,409,254	11,453,608	
5	Net Investment (Lines 2 + 3 + 4)			$5,691,363	$6,804,252	$7,064,395	$7,552,501	$7,785,760	$8,226,924	$8,558,118	$9,753,440	$10,413,292	$11,065,946	$11,358,900	$11,409,254	$11,453,608	
6	Average Net Investment				$6,247,807	$6,934,324	$7,308,448	$7,669,131	$8,006,342	$8,392,521	$9,155,779	$10,083,366	$10,739,619	$11,212,423	$11,384,077	$11,431,431	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		10,240	11,365	11,978	12,569	13,122	13,755	14,429	15,891	16,925	17,670	17,940	18,015	173,899
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		29,707	32,971	34,750	36,465	38,069	39,905	44,027	48,488	51,643	53,917	54,742	54,970	519,654
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	1.4860%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.000525			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$39,947	$44,336	$46,728	$49,034	$51,191	$53,660	$58,456	$64,379	$68,568	$71,587	$72,682	$72,985	693,553
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$39,947	$44,336	$46,728	$49,034	$51,191	$53,660	$58,456	$64,379	$68,568	$71,587	$72,682	$72,985	693,553
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Base				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				37,105	41,181	43,403	45,545	47,549	49,842	54,297	59,798	63,689	66,494	67,511	67,792	644,207
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$37,105	$41,181	$43,403	$45,545	$47,549	$49,842	$54,297	$59,798	$63,689	$66,494	$67,511	$67,792	$644,207

Notes:
(A) N/A
(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 120007-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	161,754	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,454,898	$1,293,144	$1,293,144	$1,293,144	$1,293,144	
3	Less: Accumulated Depreciation			(385,464)	(388,039)	(390,614)	(393,189)	(395,764)	(398,339)	(400,914)	(403,489)	(406,064)	(246,885)	(354,141)	(356,312)	(358,483)	
3a	Regulatory Asset Balance (G)			239,885	219,894	199,904	179,914	159,923	139,933	119,942	99,952	79,962	59,971	136,309	107,561	78,814	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,309,319	$1,286,754	$1,264,188	$1,241,623	$1,219,057	$1,196,492	$1,173,927	$1,151,361	$1,128,796	$1,106,230	$1,075,312	$1,044,393	$1,013,475	
6	Average Net Investment				$1,298,036	$1,275,471	$1,252,905	$1,230,340	$1,207,775	$1,185,209	$1,162,644	$1,140,078	$1,117,513	$1,090,771	$1,059,853	$1,028,934	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		2,128	2,091	2,053	2,016	1,979	1,943	1,831	1,797	1,761	1,719	1,670	1,622	22,610
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		6,172	6,065	5,957	5,850	5,743	5,636	5,592	5,484	5,373	5,244	5,096	4,947	67,159
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,171	2,171	2,171	29,688
	b. Amortization (G)				19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	28,747	28,747	28,747	266,156
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				(964)	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	907	907	907	9,877
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$29,902	$31,736	$31,590	$31,446	$31,302	$31,159	$31,003	$30,861	$30,714	$38,788	$38,591	$38,394	395,491
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				29,902	31,736	31,590	31,446	31,302	31,159	31,003	30,861	30,714	38,788	38,591	38,394	395,491
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)				0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				28,683	30,443	30,303	30,165	30,027	29,889	29,740	29,603	29,462	37,207	37,019	36,830	379,370
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$28,683	$30,443	$30,303	$30,165	$30,027	$29,889	$29,740	$29,603	$29,462	$37,207	$37,019	$36,830	$379,370

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.

(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost. January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

(G) Investment amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$159,014	($1,299)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$157,716
	b. Clearings to Plant				159,014	(1,299)	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$86,541,985	86,701,000	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	86,699,701	
3	Less: Accumulated Depreciation			($1,572,913)	(1,682,997)	(1,793,080)	(1,903,163)	(2,013,246)	(2,123,329)	(2,233,412)	(2,343,495)	(2,453,578)	(2,563,661)	(2,673,744)	(2,783,827)	(2,893,910)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$84,969,073	$85,018,004	$84,906,621	$84,796,538	$84,686,455	$84,576,372	$84,466,289	$84,356,206	$84,246,123	$84,136,040	$84,025,957	$83,915,874	$83,805,791	
6	Average Net Investment				$84,993,538	$84,962,313	$84,851,580	$84,741,497	$84,631,414	$84,521,331	$84,411,248	$84,301,165	$84,191,082	$84,080,999	$83,970,916	$83,860,833	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		139,297	139,246	139,065	138,885	138,704	138,523	133,025	132,852	132,678	132,504	132,332	132,158	1,629,269
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		404,128	403,980	403,453	402,930	402,405	401,883	405,907	405,378	404,848	404,319	403,790	403,261	4,846,282
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				110,084	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	1,320,997
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)				(12,808)	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	28,904
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$640,701	$657,101	$656,393	$655,690	$654,984	$654,281	$652,807	$652,105	$651,401	$650,698	$649,997	$649,294	7,825,452
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				640,701	657,101	656,393	655,690	654,984	654,281	652,807	652,105	651,401	650,698	649,997	649,294	7,825,452
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				595,115	610,348	609,691	609,038	608,382	607,729	606,360	605,708	605,054	604,401	603,750	603,097	7,268,671
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$595,115	$610,348	$609,691	$609,038	$608,382	$607,729	$606,360	$605,708	$605,054	$604,401	$603,750	$603,097	$7,268,671

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Depreciation calculated in CAIR Crystal River section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.

(D) Property taxes calculated in CAIR Crystal River section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost. January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Schedule of Amortization and Return
For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0154401 Ammonia Inventory			$542,621	$542,621	$542,621	$540,418	$589,673	$587,967	$633,965	$572,877	$572,877	$572,877	$572,877	$572,877	$572,877	$572,877
	b. 0154200 Limestone Inventory			$1,193,107	3,648	3,648	881	(34,243)	(151,682)	(146,551)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)
2	Total Working Capital			$1,735,728	$546,269	$546,269	$541,299	$555,429	$436,285	$487,414	$518,827	$518,827	$518,827	$518,827	$518,827	$518,827	518,827
3	Average Net Investment				1,140,998	546,269	543,784	548,364	495,857	461,850	503,121	518,827	518,827	518,827	518,827	518,827	
4	Return on Average Net Working Capital Balance (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		1,870	895	891	899	813	757	793	818	818	818	818	818	$11,006
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		5,425	2,597	2,586	2,607	2,358	2,196	2,419	2,495	2,495	2,495	2,495	2,495	32,663
5	Total Return Component (B)				7,295	3,493	3,477	3,506	3,170	2,953	3,212	3,313	3,313	3,313	3,313	3,313	43,669
6	Expense Dr (Cr)																
	a. 0502030 Ammonia Expense				0	0	22,715	65,144	130,334	133,126	226,500	246,100	193,000	177,800	25,600	25,600	1,245,918
	b. 0502040 Limestone Expense				(3,648)	0	16,800	95,563	330,019	296,876	136,621	315,710	276,596	321,891	389,488	486,556	2,662,472
	c. 0502050 Dibasic Acid Expense				0	0	0	0	0	0	1,700	1,900	1,500	1,400	200	200	6,900
	d. 0502070 Gypsum Disposal/Sale				(25)	0	(13,121)	(116,191)	(237,620)	(252,571)	(12,109)	(27,918)	(24,414)	(28,417)	(34,456)	(43,196)	(790,038)
	e. 0502040 Hydrated Lime Expense				0	0	15,327	68,419	142,498	147,593	190,800	207,200	162,700	150,000	21,650	21,650	1,127,835
	f. 0502300 Caustic Expense				0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)				(3,673)	0	41,720	112,935	365,231	325,023	543,512	742,992	609,382	622,674	402,482	490,810	4,253,088
8	Total System Recoverable Expenses (Lines 5 + 7)				$3,623	$3,493	$45,197	$116,441	$368,401	$327,976	$546,724	$746,304	$612,695	$625,986	$405,794	$494,122	4,296,757
	a. Recoverable Costs Allocated to Energy				3,623	3,493	45,197	116,441	368,401	327,976	546,724	746,304	612,695	625,986	405,794	494,122	4,296,757
	b. Recoverable Costs Allocated to Demand				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor				0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.91693	0.92073	0.93259	0.93075	0.95529	0.94423	
10	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)				3,534	3,399	42,729	111,096	337,161	299,606	501,309	687,145	571,395	582,639	387,652	466,566	3,994,234
12	Retail Demand-Related Recoverable Costs (E)				0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)				$ 3,534	$ 3,399	$ 42,729	$ 111,096	$ 337,161	$ 299,606	$ 501,309	$ 687,145	$ 571,395	$ 582,639	$ 387,652	$ 466,566	$ 3,994,234

Notes:

(A) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(B) Line 5 is reported on Capital Schedule

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

(D) Line 8a x Line 9

(E) Line 8b x Line 10

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
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Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	11,324	
3	Less: Accumulated Depreciation	(4,046)	(4,075)	(4,104)	(4,133)	(4,162)	(4,191)	(4,220)	(4,249)	(4,278)	(4,307)	(4,336)	(4,365)	(4,394)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$7,278	$7,249	$7,220	$7,191	$7,162	$7,133	$7,104	$7,075	$7,046	$7,017	$6,988	$6,959	$6,930	
6	Average Net Investment		$7,264	$7,235	$7,206	$7,177	$7,148	$7,119	$7,090	$7,061	$7,032	$7,003	$6,974	$6,945	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec												
	a. Debt Component	1.97%	1.89%	12	12	12	12	12	12	11	11	11	11	11	11	138
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%	35	34	34	34	34	34	34	34	34	34	33	408
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.0658%			29	29	29	29	29	29	29	29	29	29	29	348
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.007755			(16)	7	7	7	7	7	7	7	7	7	7	61
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$60	$82	$82	$82	$82	$82	$81	$81	$81	$81	$81	$80	955
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$60	$82	$82	$82	$82	$82	$81	$81	$81	$81	$81	$80	955
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)			0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			60	82	82	82	82	82	81	81	81	81	81	80	951
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$60	$82	$82	$82	$82	$82	$81	$81	$81	$81	$81	$80	$951

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894).
See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
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Duke Energy Florida
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Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Base (Project 10.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation			(49,552)	(49,848)	(50,144)	(50,440)	(50,736)	(51,032)	(51,328)	(51,624)	(51,920)	(52,216)	(52,512)	(52,808)	(53,104)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$119,389	$119,093	$118,797	$118,501	$118,205	$117,909	$117,613	$117,317	$117,021	$116,725	$116,429	$116,133	$115,837	
6	Average Net Investment				$119,241	$118,945	$118,649	$118,353	$118,057	$117,761	$117,465	$117,169	$116,873	$116,577	$116,281	$115,985	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		195	195	194	194	193	193	185	185	184	184	183	183	2,268
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		567	566	564	563	561	560	565	563	562	561	559	558	6,749
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	2.1000%			296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.008573			236	121	121	121	121	121	121	121	121	121	121	121	1,567
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,294	$1,178	$1,175	$1,174	$1,171	$1,170	$1,167	$1,165	$1,163	$1,162	$1,159	$1,158	14,136
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,294	$1,178	$1,175	$1,174	$1,171	$1,170	$1,167	$1,165	$1,163	$1,162	$1,159	$1,158	14,136
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				1,202	1,094	1,091	1,090	1,088	1,087	1,084	1,082	1,080	1,079	1,077	1,076	13,130
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,202	$1,094	$1,091	$1,090	$1,088	$1,087	$1,084	$1,082	$1,080	$1,079	$1,077	$1,076	$13,130

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation			(31,529)	(31,732)	(31,935)	(32,138)	(32,341)	(32,544)	(32,747)	(32,950)	(33,153)	(33,356)	(33,559)	(33,762)	(33,965)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$44,477	$44,274	$44,071	$43,868	$43,665	$43,462	$43,259	$43,056	$42,853	$42,650	$42,447	$42,244	$42,041	
6	Average Net Investment				$44,376	$44,173	$43,970	$43,767	$43,564	$43,361	$43,158	$42,955	$42,752	$42,549	$42,346	$42,143	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		73	72	72	72	71	71	68	68	67	67	67	66	834
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		211	210	209	208	207	206	208	207	206	205	204	203	2,484
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	3.2000%			203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.009890			(40)	63	63	63	63	63	63	63	63	63	63	63	653
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$447	$548	$547	$546	$544	$543	$542	$541	$539	$538	$537	$535	6,407
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$447	$548	$547	$546	$544	$543	$542	$541	$539	$538	$537	$535	6,407
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)				0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				325	398	398	397	396	395	394	393	392	391	390	389	4,658
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$325	$398	$398	$397	$396	$395	$394	$393	$392	$391	$390	$389	$4,658

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-10-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: Effluent Limitation Guidelines CRN - Energy (Project 15.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$31,742	$36,702	$22,532	$90,385	$33,067	$16,401	$0	$0	$0	$0	$0	$0	$230,828
	b. Clearings to Plant				0	0	0	0	2,641,711	16,401	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	0	0	0	0	2,641,711	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	
3	Less: Accumulated Depreciation			0	0	0	0	0	(5,438)	(10,909)	(16,380)	(21,851)	(27,322)	(32,793)	(38,264)	(43,735)	
4	CWIP - Non-Interest Bearing			2,427,284	2,459,026	2,495,727	2,518,260	2,608,644	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,427,284	$2,459,026	$2,495,727	$2,518,260	$2,608,644	$2,636,273	$2,647,203	$2,641,732	$2,636,261	$2,630,790	$2,625,319	$2,619,848	$2,614,377	
6	Average Net Investment				$2,443,155	$2,477,376	$2,506,993	$2,563,452	$2,622,459	$2,641,738	$2,644,467	$2,638,996	$2,633,525	$2,628,054	$2,622,583	$2,617,112	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		4,004	4,060	4,109	4,201	4,298	4,330	4,167	4,159	4,150	4,142	4,133	4,124	49,877
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		11,617	11,779	11,920	12,189	12,469	12,561	12,716	12,690	12,664	12,637	12,611	12,585	148,438
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	2.4700%			0	0	0	0	5,438	5,471	5,471	5,471	5,471	5,471	5,471	5,471	43,735
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000525			0	0	0	0	116	116	116	116	116	116	116	116	928
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$15,621	$15,839	$16,029	$16,390	$22,321	$22,478	$22,470	$22,436	$22,401	$22,366	$22,331	$22,296	242,978
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$15,621	$15,839	$16,029	$16,390	$22,321	$22,478	$22,470	$22,436	$22,401	$22,366	$22,331	$22,296	242,978
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				$14,510	$14,712	$14,889	$15,224	$20,733	$20,879	$20,871	$20,840	$20,807	$20,775	$20,742	$20,710	225,692
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$14,510	$14,712	$14,889	$15,224	$20,733	$20,879	$20,871	$20,840	$20,807	$20,775	$20,742	$20,710	$225,692

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Return on Capital Investments, Depreciation and Taxes
For Project: NPDES - Intermediate (Project 16)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	
3	Less: Accumulated Depreciation			(2,144,574)	(2,180,246)	(2,215,918)	(2,251,590)	(2,287,262)	(2,322,934)	(2,358,606)	(2,394,278)	(2,429,950)	(2,465,622)	(2,501,294)	(2,536,966)	(2,572,638)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$10,697,296	$10,661,624	$10,625,952	$10,590,280	$10,554,608	$10,518,936	$10,483,264	$10,447,592	$10,411,920	$10,376,248	$10,340,576	$10,304,904	$10,269,232	
6	Average Net Investment				$10,679,460	$10,643,788	$10,608,116	$10,572,444	$10,536,772	$10,501,100	$10,465,428	$10,429,756	$10,394,084	$10,358,412	$10,322,740	$10,287,068	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.97%	1.89%		17,503	17,444	17,386	17,327	17,269	17,210	16,493	16,436	16,380	16,324	16,268	16,212	202,252
	b. Equity Component Grossed Up For Taxes	5.71%	5.77%		50,779	50,609	50,440	50,270	50,100	49,931	50,325	50,153	49,982	49,810	49,639	49,467	601,505
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	3.3333%			35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	428,064
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.008150			(9,561)	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	86,381
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$94,393	$112,447	$112,220	$111,991	$111,763	$111,535	$111,212	$110,983	$110,756	$110,528	$110,301	$110,073	1,318,202
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$94,393	$112,447	$112,220	$111,991	$111,763	$111,535	$111,212	$110,983	$110,756	$110,528	$110,301	$110,073	1,318,202
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)				0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				68,627	81,752	81,587	81,421	81,255	81,089	80,854	80,688	80,523	80,357	80,192	80,026	958,373
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$68,627	$81,752	$81,587	$81,421	$81,255	$81,089	$80,854	$80,688	$80,523	$80,357	$80,192	$80,026	$958,373

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 4 & 5 - Energy (Project 17)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	
3	Less: Accumulated Depreciation			(345,965)	(352,547)	(359,129)	(365,711)	(372,293)	(378,875)	(385,457)	(392,039)	(398,621)	(405,203)	(411,785)	(418,367)	(424,949)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$3,344,222	$3,337,640	$3,331,058	$3,324,476	$3,317,894	$3,311,312	$3,304,730	$3,298,148	$3,291,566	$3,284,984	$3,278,402	$3,271,820	$3,265,238	
6	Average Net Investment				$3,340,931	$3,334,349	$3,327,767	$3,321,185	$3,314,603	$3,308,021	$3,301,439	$3,294,857	$3,288,275	$3,281,693	$3,275,111	$3,268,529	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.96670%	1.89%		5,476	5,465	5,454	5,443	5,432	5,422	5,203	5,192	5,182	5,172	5,161	5,151	63,753
	b. Equity Component Grossed Up For Taxes	5.70577%	5.77%		15,885	15,854	15,823	15,792	15,760	15,729	15,876	15,844	15,812	15,781	15,749	15,717	189,622
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	Blended			6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	78,984
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000525			(1,577)	161	161	161	161	161	161	161	161	161	161	161	194
	e. Other (E)				(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(7,160)
9	Total System Recoverable Expenses (Lines 7 + 8)				$25,770	$27,465	$27,423	$27,381	$27,338	$27,297	$27,225	$27,182	$27,140	$27,099	$27,056	$27,014	325,393
	a. Recoverable Costs Allocated to Energy				25,770	27,465	27,423	27,381	27,338	27,297	27,225	27,182	27,140	27,099	27,056	27,014	325,393
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.91693	0.92073	0.93259	0.93075	0.95529	0.94423	
11	Demand Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)				$25,143	$26,732	$25,926	$26,125	$25,020	$24,936	$24,964	$25,028	$25,311	$25,223	$25,847	$25,508	$305,763
13	Retail Demand-Related Recoverable Costs (G)				0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$25,143	$26,732	$25,926	$26,125	$25,020	$24,936	$24,964	$25,028	$25,311	$25,223	$25,847	$25,508	$305,763

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.

(F) Line 9a x Line 10

(G) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - ANCLOTE GAS CONVERSION - Energy (Project 17.1)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	$133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	
3	Less: Accumulated Depreciation	(17,457,598)	(17,700,012)	(17,942,426)	(18,184,840)	(18,427,254)	(18,669,668)	(18,912,082)	(19,154,496)	(19,396,910)	(19,639,324)	(19,881,738)	(20,124,152)	(20,366,566)	
4	CWIP - AFUDC Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$116,460,669	$116,218,255	$115,975,841	$115,733,427	$115,491,013	$115,248,599	$115,006,185	$114,763,771	$114,521,357	$114,278,943	$114,036,529	$113,794,115	$113,551,701	
6	Average Net Investment		$116,339,462	$116,097,048	$115,854,634	$115,612,220	$115,369,806	$115,127,392	$114,884,978	$114,642,564	$114,400,150	$114,157,736	$113,915,322	$113,672,908	
7	Return on Average Net Investment (B)	Jan-Jun / Jul-Dec													
	a. Debt Component	1.97% / 1.89%	190,671	190,273	189,876	189,479	189,081	188,684	181,049	180,667	180,285	179,903	179,521	179,139	2,218,628
	b. Equity Component Grossed Up For Taxes	5.71% / 5.77%	553,172	552,019	550,866	549,714	548,561	547,409	552,446	551,280	550,114	548,949	547,783	546,617	6,598,930
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 2.1722%		242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	2,908,968
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.006390		(211,077)	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	573,344
	e. Other (E)		(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(177,534)
9	Total System Recoverable Expenses (Lines 7 + 8)		$760,385	$1,041,223	$1,039,673	$1,038,124	$1,036,573	$1,035,024	$1,032,426	$1,030,878	$1,029,330	$1,027,783	$1,026,235	$1,024,687	12,122,336
	a. Recoverable Costs Allocated to Energy		760,385	1,041,223	1,039,673	1,038,124	1,036,573	1,035,024	1,032,426	1,030,878	1,029,330	1,027,783	1,026,235	1,024,687	12,122,336
	b. Recoverable Costs Allocated to Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor		0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.91693	0.92073	0.93259	0.93075	0.95529	0.94423	
11	Demand Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)		$741,908	$1,013,422	$982,906	$990,474	$948,671	$945,494	$946,664	$949,161	$959,946	$956,613	$980,355	$967,542	$11,383,156
13	Retail Demand-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$741,908	$1,013,422	$982,906	$990,474	$948,671	$945,494	$946,664	$949,161	$959,946	$956,613	$980,355	$967,542	$11,383,156

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.

(F) Line 9a x Line 10

(G) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 1 & 2 - Energy (Project 17.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	22,681,074	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$22,681,074	22,681,074	22,681,074	22,681,074	22,681,074	22,681,074	22,681,074	22,681,074	22,681,074	22,681,074	22,681,074	22,681,074	(0)	
3	Less: Accumulated Depreciation		(3,846,177)	(3,916,110)	(3,986,043)	(4,055,976)	(4,125,909)	(4,195,842)	(4,265,775)	(4,335,708)	(4,405,641)	(4,475,574)	(4,545,507)	(4,615,440)	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$18,834,897	$18,764,964	$18,695,031	$18,625,098	$18,555,165	$18,485,232	$18,415,299	$18,345,366	$18,275,433	$18,205,500	$18,135,567	$18,065,634	($0)	
6	Average Net Investment			$18,799,930	$18,729,997	$18,660,064	$18,590,131	$18,520,198	$18,450,265	$18,380,332	$18,310,399	$18,240,466	$18,170,533	$18,100,600	$9,032,817	
7	Return on Average Net Investment (B)	Jan-Jun Jul-Dec														
	a. Debt Component	1.9667% 1.89%		30,812	30,697	30,582	30,468	30,353	30,238	28,966	28,856	28,745	28,635	28,525	28,415	355,292
	b. Equity Component Grossed Up For Taxes	5.7058% 5.77%		89,390	89,058	88,725	88,392	88,060	87,727	88,385	88,049	87,713	87,376	87,040	86,704	1,056,619
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.7000%		69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	69,933	839,196
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000525		(9,619)	992	992	992	992	992	992	992	992	992	992	992	1,293
	e. Other (E)			(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(10,540)	(126,475)
9	Total System Recoverable Expenses (Lines 7 + 8)			$169,976	$180,140	$179,692	$179,245	$178,798	$178,350	$177,736	$177,290	$176,843	$176,396	$175,950	$175,504	2,125,925
	a. Recoverable Costs Allocated to Energy			169,976	180,140	179,692	179,245	178,798	178,350	177,736	177,290	176,843	176,396	175,950	175,504	2,125,925
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.97570	0.97330	0.94540	0.95410	0.91520	0.91350	0.91693	0.92073	0.93259	0.93075	0.95529	0.94423	
11	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)			$165,846	$175,331	$169,881	$171,018	$163,636	$162,923	$162,972	$163,237	$164,923	$164,182	$168,084	$165,717	$1,997,750
13	Retail Demand-Related Recoverable Costs (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$165,846	$175,331	$169,881	$171,018	$163,636	$162,923	$162,972	$163,237	$164,923	$164,182	$168,084	$165,717	$1,997,750

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.

(F) Line 9a x Line 10

(G) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Docket No. 20200007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Base (Project 18)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$268,356	$268,356	$268,356	$268,356	$268,356	$1,341,780
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	446,090	
3	Less: Accumulated Depreciation		(20,252)	(21,058)	(21,864)	(22,670)	(23,476)	(24,282)	(25,088)	(25,894)	(26,700)	(27,506)	(28,312)	(29,118)	(29,924)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	268,356	536,712	805,068	1,073,424	1,341,780	
5	Net Investment (Lines 2 + 3 + 4)		$425,838	$425,032	$424,226	$423,420	$422,614	$421,808	$421,002	$420,196	$687,746	$955,296	$1,222,846	$1,490,396	$1,757,946	
6	Average Net Investment			$425,435	$424,629	$423,823	$423,017	$422,211	$421,405	$420,599	$553,971	$821,521	$1,089,071	$1,356,621	$1,624,171	
7	Return on Average Net Investment (B)	Jan-Jun Jul-Dec														
	a. Debt Component	1.97% 1.89%		697	696	695	693	692	691	663	873	1,295	1,716	2,138	2,560	13,409
	b. Equity Component Grossed Up For Taxes	5.71% 5.77%		2,023	2,019	2,015	2,011	2,008	2,004	2,023	2,664	3,950	5,237	6,524	7,810	40,288
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.1695%		806	806	806	806	806	806	806	806	806	806	806	806	9,672
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000525		(142)	20	20	20	20	20	20	20	20	20	20	20	78
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$3,384	$3,541	$3,536	$3,530	$3,526	$3,521	$3,512	$4,363	$6,071	$7,779	$9,488	$11,196	63,447
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,384	3,541	3,536	3,530	3,526	3,521	3,512	4,363	6,071	7,779	9,488	11,196	63,447
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			3,143	3,289	3,284	3,279	3,275	3,270	3,262	4,053	5,639	7,226	8,813	10,399	58,932
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$3,143	$3,289	$3,284	$3,279	$3,275	$3,270	$3,262	$4,053	$5,639	$7,226	$8,813	$10,399	$58,932

Notes:

(A) N/A

(B) Jan - Jun 2020 Line 6 x 7.67% x 1/12. Jul - Dec 2020 Line 6 x 7.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.31% (Jan-Jun) and 4.36% (Jul-Dec), and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2020 - December 2020

Capital Structure and Cost Rates

Class of Capital	Retail Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$ 4,874,577,393	41.01%	0.10500	4.31%	5.71%
PS	-	0.00%	0.00000	0.00%	0.00%
LTD	4,845,025,196	40.77%	0.04701	1.92%	1.92%
STD	(59,426,995)	-0.50%	-0.00358	0.00%	0.00%
CD-Active	176,756,874	1.49%	0.02378	0.04%	0.04%
CD-Inactive	1,853,499	0.02%	0.00000	0.00%	0.00%
ADIT	2,026,313,275	17.05%	0.00000	0.00%	0.00%
FAS 109	-	0.00%	0.00000	0.00%	0.00%
ITC	19,805,922	0.17%	0.07715	0.01%	0.01%
Total	$11,884,905,162	100.00%		6.27%	7.67%
			Total Debt	1.97%	1.97%
			Total Equity	4.31%	5.71%

May 2019 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

The May 2019 DEF Surveillance Report reflects the tax reform adjustments as set forth in Paragraph 16 of DEF's 2017 Settlement.

Class of Capital	Retail Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$ 5,587,139,333	41.48%	0.10500	4.36%	5.77%
PS	-	0.00%	0.00000	0.00%	0.00%
LTD	5,219,534,862	38.75%	0.04616	1.79%	1.79%
STD	228,721,050	1.70%	0.02101	0.04%	0.04%
CD-Active	184,176,907	1.37%	0.02434	0.03%	0.03%
CD-Inactive	1,820,718	0.01%	0.00000	0.00%	0.00%
ADIT	2,189,708,749	16.26%	0.00000	0.00%	0.00%
FAS 109	-	0.00%	0.00000	0.00%	0.00%
ITC	58,310,573	0.43%	0.07658	0.03%	0.03%
Total	$ 13,469,412,193	100.00%		6.25%	7.66%
			Total Debt	1.89%	1.89%
			Total Equity	4.36%	5.77%

May 2020 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Capital Program Detail

January 2020 - December 2020
Actuals for the Period January 2020 - June 2020
Estimates for the Period July 2020 - December 2020
Docket No. 20200007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 24
PARTY: CAM-4
DESCRIPTION: Capital Program
DetailJanuary 2020 – December 2020

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	
3	Less: Accumulated Depreciation				(469,383)	(473,068)	(476,753)	(480,438)	(484,123)	(487,808)	(491,493)	(495,178)	(498,863)	(502,548)	(506,233)	(509,918)	(513,603)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$1,004,418	$1,000,733	$997,048	$993,363	$989,678	$985,993	$982,308	$978,623	$974,938	$971,253	$967,568	$963,883	$960,198	
6	Average Net Investment					1,002,576	998,891	995,206	991,521	987,836	984,151	980,466	976,781	973,096	969,411	965,726	962,041	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		1,643	1,637	1,631	1,625	1,619	1,613	1,545	1,539	1,534	1,528	1,522	1,516	18,952
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		4,767	4,750	4,732	4,714	4,697	4,679	4,715	4,697	4,679	4,662	4,644	4,626	56,362
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	3.0000%				3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.8150%				(1,425)	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	9,586
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$8,670	$11,073	$11,049	$11,025	$11,002	$10,978	$10,946	$10,922	$10,899	$10,876	$10,852	$10,828	$129,120
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$8,670	$11,073	$11,049	$11,025	$11,002	$10,978	$10,946	$10,922	$10,899	$10,876	$10,852	$10,828	$129,120

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation				(1,272,803)	(1,281,942)	(1,291,081)	(1,300,220)	(1,309,359)	(1,318,498)	(1,327,637)	(1,336,776)	(1,345,915)	(1,355,054)	(1,364,193)	(1,373,332)	(1,382,471)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$388,861	$379,722	$370,583	$361,444	$352,305	$343,166	$334,027	$324,888	$315,749	$306,610	$297,471	$288,332	$279,193	
6	Average Net Investment					384,292	375,153	366,014	356,875	347,736	338,597	329,458	320,319	311,180	302,041	292,902	283,763	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		630	615	600	585	570	555	519	505	490	476	462	447	6,454
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		1,827	1,784	1,740	1,697	1,653	1,610	1,584	1,540	1,496	1,452	1,408	1,365	19,156
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	6.6000%				9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.7220%				(1,426)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	9,574
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$10,170	$12,538	$12,479	$12,421	$12,362	$12,304	$12,242	$12,184	$12,125	$12,067	$12,009	$11,951	$144,852
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$10,170	$12,538	$12,479	$12,421	$12,362	$12,304	$12,242	$12,184	$12,125	$12,067	$12,009	$11,951	$144,852

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	178,938	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	0	0	0	0	
3	Less: Accumulated Depreciation				(107,081)	(107,797)	(108,513)	(109,229)	(109,945)	(110,661)	(111,377)	(112,093)	(112,809)	65,413	0	0	0	
3a	Regulatory Asset Balance (C)				0	0	0	0	0	0	0	0	0	0	59,962	54,511	49,060	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$71,857	$71,141	$70,425	$69,709	$68,993	$68,277	$67,561	$66,845	$66,129	$65,413	$59,962	$54,511	$49,060	
6	Average Net Investment					71,499	70,783	70,067	69,351	68,635	67,919	67,203	66,487	65,771	62,688	57,237	51,785	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		117	116	115	114	112	111	106	105	104	99	90	82	1,271
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		340	337	333	330	326	323	323	320	316	301	275	249	3,773
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	4.8000%				716	716	716	716	716	716	716	716	716	0	0	0	6,444
	b. Amortization (C)					0	0	0	0	0	0	0	0	0	5,451	5,451	5,451	16,353
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.8000%				(2,307)	119	119	119	119	119	119	119	119	0	0	0	(1,355)
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					($1,134)	$1,288	$1,283	$1,279	$1,273	$1,269	$1,264	$1,260	$1,255	$5,851	$5,816	$5,782	$26,487
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					($1,134)	$1,288	$1,283	$1,279	$1,273	$1,269	$1,264	$1,260	$1,255	$5,851	$5,816	$5,782	$26,487

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3	Less: Accumulated Depreciation				(264,349)	(266,171)	(267,993)	(269,815)	(271,637)	(273,459)	(275,281)	(277,103)	(278,925)	(280,747)	(282,569)	(284,391)	(286,213)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$465,946	$464,124	$462,302	$460,480	$458,658	$456,836	$455,014	$453,192	$451,370	$449,548	$447,726	$445,904	$444,082	
6	Average Net Investment					465,035	463,213	461,391	459,569	457,747	455,925	454,103	452,281	450,459	448,637	446,815	444,993	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		762	759	756	753	750	747	716	713	710	707	704	701	8,778
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		2,211	2,202	2,194	2,185	2,176	2,168	2,184	2,175	2,166	2,157	2,149	2,140	26,107
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.9936%				1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	21,864
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	1.1030%				(1,755)	671	671	671	671	671	671	671	671	671	671	671	5,626
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$3,040	$5,454	$5,443	$5,431	$5,419	$5,408	$5,393	$5,381	$5,369	$5,357	$5,346	$5,334	$62,375
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$3,040	$5,454	$5,443	$5,431	$5,419	$5,408	$5,393	$5,381	$5,369	$5,357	$5,346	$5,334	$62,375

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(C) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation				(426,600)	(429,452)	(432,304)	(435,156)	(438,008)	(440,860)	(443,712)	(446,564)	(449,416)	(452,268)	(455,120)	(457,972)	(460,824)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$610,599	$607,747	$604,895	$602,043	$599,191	$596,339	$593,487	$590,635	$587,783	$584,931	$582,079	$579,227	$576,375	
6	Average Net Investment					609,173	606,321	603,469	600,617	597,765	594,913	592,061	589,209	586,357	583,505	580,653	577,801	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		998	994	989	984	980	975	933	929	924	920	915	911	11,452
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		2,897	2,883	2,869	2,856	2,842	2,829	2,847	2,833	2,820	2,806	2,792	2,778	34,052
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	3.3000%				2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.8390%				(1,701)	725	725	725	725	725	725	725	725	725	725	725	6,274
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$5,046	$7,454	$7,435	$7,417	$7,399	$7,381	$7,357	$7,339	$7,321	$7,303	$7,284	$7,266	$86,002
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$5,046	$7,454	$7,435	$7,417	$7,399	$7,381	$7,357	$7,339	$7,321	$7,303	$7,284	$7,266	$86,002

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	
3	Less: Accumulated Depreciation				(916,094)	(923,931)	(931,768)	(939,605)	(947,442)	(955,279)	(963,116)	(970,953)	(978,790)	(986,627)	(994,464)	(1,002,301)	(1,010,138)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$2,700,810	$2,692,973	$2,685,136	$2,677,299	$2,669,462	$2,661,625	$2,653,788	$2,645,951	$2,638,114	$2,630,277	$2,622,440	$2,614,603	$2,606,766	
6	Average Net Investment					2,696,891	2,689,054	2,681,217	2,673,380	2,665,543	2,657,706	2,649,869	2,642,032	2,634,195	2,626,358	2,618,521	2,610,684	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		4,420	4,407	4,394	4,381	4,369	4,356	4,176	4,164	4,151	4,139	4,127	4,114	51,198
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		12,823	12,786	12,749	12,711	12,674	12,637	12,742	12,705	12,667	12,629	12,592	12,554	152,269
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.6000%				7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	94,044
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.8220%				52	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	27,310
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$25,132	$27,508	$27,458	$27,407	$27,358	$27,308	$27,233	$27,184	$27,133	$27,083	$27,034	$26,983	$324,821
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$25,132	$27,508	$27,458	$27,407	$27,358	$27,308	$27,233	$27,184	$27,133	$27,083	$27,034	$26,983	$324,821

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation				(66,126)	(66,367)	(66,608)	(66,849)	(67,090)	(67,331)	(67,572)	(67,813)	(68,054)	(68,295)	(68,536)	(68,777)	(69,018)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$75,309	$75,068	$74,827	$74,586	$74,345	$74,104	$73,863	$73,622	$73,381	$73,140	$72,899	$72,658	$72,417	
6	Average Net Investment					75,188	74,947	74,706	74,465	74,224	73,983	73,742	73,501	73,260	73,019	72,778	72,537	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		123	123	122	122	122	121	116	116	115	115	115	114	1,424
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		358	356	355	354	353	352	355	353	352	351	350	349	4,238
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.0482%				241	241	241	241	241	241	241	241	241	241	241	241	2,892
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.9910%				(2,309)	117	117	117	117	117	117	117	117	117	117	117	(1,022)
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					($1,587)	$837	$835	$834	$833	$831	$829	$827	$825	$824	$823	$821	$7,532
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					($1,587)	$837	$835	$834	$833	$831	$829	$827	$825	$824	$823	$821	$7,532

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation				0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (C)				169,932	155,771	141,610	127,449	113,288	99,127	84,966	70,805	56,644	42,483	28,322	14,161	0	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$169,932	$155,771	$141,610	$127,449	$113,288	$99,127	$84,966	$70,805	$56,644	$42,483	$28,322	$14,161	$0	
6	Average Net Investment					162,851	148,690	134,529	120,368	106,207	92,046	77,885	63,724	49,563	35,402	21,241	7,080	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		267	244	220	197	174	151	123	100	78	56	33	11	1,654
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		774	707	640	572	505	438	375	306	238	170	102	34	4,861
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	5.4000%				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (C)					14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	14,161	169,932
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.8270%				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$15,202	$15,112	$15,021	$14,930	$14,840	$14,750	$14,659	$14,567	$14,477	$14,387	$14,296	$14,206	$176,447
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$15,202	$15,112	$15,021	$14,930	$14,840	$14,750	$14,659	$14,567	$14,477	$14,387	$14,296	$14,206	$176,447

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(C) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	33,092	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	0	
3	Less: Accumulated Depreciation			(20,787)	(20,889)	(20,991)	(21,093)	(21,195)	(21,297)	(21,399)	(21,501)	(21,603)	(21,705)	(21,807)	(21,909)	0	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$12,305	$12,203	$12,101	$11,999	$11,897	$11,795	$11,693	$11,591	$11,489	$11,387	$11,285	$11,183	$0	
6	Average Net Investment				12,254	12,152	12,050	11,948	11,846	11,744	11,642	11,540	11,438	11,336	11,234	5,592	
7	Return on Average Net Investment (A)		Jan-Jun Jul-Dec														
	a. Debt Component		1.97% 1.89%		20	20	20	20	19	19	18	18	18	18	18	18	226
	b. Equity Component Grossed Up For Taxes		5.71% 5.77%		58	58	57	57	56	56	56	55	55	55	54	54	671
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.7000%			102	102	102	102	102	102	102	102	102	102	102	102	1,224
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.1645%			5	5	5	5	5	5	5	5	5	5	5	5	60
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$185	$185	$184	$184	$182	$182	$181	$180	$180	$180	$179	$179	$2,181
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$185	$185	$184	$184	$182	$182	$181	$180	$180	$180	$179	$179	$2,181

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	
3	Less: Accumulated Depreciation			($24,748)	(27,678)	(30,608)	(33,538)	(36,468)	(39,398)	(42,328)	(45,258)	(48,188)	(51,118)	(54,048)	(56,978)	(59,908)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,341,199	$2,338,269	$2,335,339	$2,332,409	$2,329,479	$2,326,549	$2,323,619	$2,320,689	$2,317,759	$2,314,829	$2,311,899	$2,308,969	$2,306,039	
6	Average Net Investment				2,339,734	2,336,804	2,333,874	2,330,944	2,328,014	2,325,084	2,322,154	2,319,224	2,316,294	2,313,364	2,310,434	2,307,504	
7	Return on Average Net Investment (A)		Jan-Jun Jul-Dec														
	a. Debt Component		1.97% 1.89%		3,835	3,830	3,825	3,820	3,815	3,811	3,660	3,655	3,650	3,646	3,641	3,636	44,824
	b. Equity Component Grossed Up For Taxes		5.71% 5.77%		11,125	11,111	11,097	11,083	11,069	11,055	11,167	11,152	11,138	11,124	11,110	11,096	133,327
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.4860%			2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	35,160
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.1645%			(389)	324	324	324	324	324	324	324	324	324	324	324	3,175
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$17,501	$18,195	$18,176	$18,157	$18,138	$18,120	$18,081	$18,061	$18,042	$18,024	$18,005	$17,986	$216,486
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$17,501	$18,195	$18,176	$18,157	$18,138	$18,120	$18,081	$18,061	$18,042	$18,024	$18,005	$17,986	$216,486

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation				(85,386)	(85,911)	(86,436)	(86,961)	(87,486)	(88,011)	(88,536)	(89,061)	(89,586)	(90,111)	(90,636)	(91,161)	(91,686)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$204,911	$204,386	$203,861	$203,336	$202,811	$202,286	$201,761	$201,236	$200,711	$200,186	$199,661	$199,136	$198,611	
6	Average Net Investment					204,649	204,124	203,599	203,074	202,549	202,024	201,499	200,974	200,449	199,924	199,399	198,874	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		335	335	334	333	332	331	318	317	316	315	314	313	3,893
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		973	971	968	966	963	961	969	966	964	961	959	956	11,577
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.1722%				525	525	525	525	525	525	525	525	525	525	525	525	6,300
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.6390%				(434)	155	155	155	155	155	155	155	155	155	155	155	1,271
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$1,399	$1,986	$1,982	$1,979	$1,975	$1,972	$1,967	$1,963	$1,960	$1,956	$1,953	$1,949	$23,041
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$1,399	$1,986	$1,982	$1,979	$1,975	$1,972	$1,967	$1,963	$1,960	$1,956	$1,953	$1,949	$23,041

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	161,754	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	0	0	0	0	
3	Less: Accumulated Depreciation				(53,033)	(53,437)	(53,841)	(54,245)	(54,649)	(55,053)	(55,457)	(55,861)	(56,265)	105,085	0	0	0	
3a	Regulatory Asset Balance (C)				0							0	0	0	96,328	87,571	78,814	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$108,721	$108,317	$107,913	$107,509	$107,105	$106,701	$106,297	$105,893	$105,489	$105,085	$96,328	$87,571	$78,814	
6	Average Net Investment					108,519	108,115	107,711	107,307	106,903	106,499	106,095	105,691	105,287	100,707	91,949	83,192	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		178	177	177	176	175	175	167	167	166	159	145	131	1,993
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		516	514	512	510	508	506	510	508	506	484	442	400	5,916
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	3.0000%				404	404	404	404	404	404	404	404	404	0	0	0	3,636
	b. Amortization (C)					0	0	0	0	0	0	0	0	0	8,757	8,757	8,757	26,271
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.8000%				(222)	108	108	108	108	108	108	108	108	0	0	0	642
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$876	$1,203	$1,201	$1,198	$1,195	$1,193	$1,189	$1,187	$1,184	$9,400	$9,344	$9,288	$38,458
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$876	$1,203	$1,201	$1,198	$1,195	$1,193	$1,189	$1,187	$1,184	$9,400	$9,344	$9,288	$38,458

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3	Less: Accumulated Depreciation				(62,449)	(62,807)	(63,165)	(63,523)	(63,881)	(64,239)	(64,597)	(64,955)	(65,313)	(65,671)	(66,029)	(66,387)	(66,745)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$212,898	$212,540	$212,182	$211,824	$211,466	$211,108	$210,750	$210,392	$210,034	$209,676	$209,318	$208,960	$208,602	
6	Average Net Investment					212,719	212,361	212,003	211,645	211,287	210,929	210,571	210,213	209,855	209,497	209,139	208,781	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		349	348	347	347	346	346	332	331	331	330	330	329	4,066
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		1,011	1,010	1,008	1,006	1,005	1,003	1,013	1,011	1,009	1,007	1,006	1,004	12,093
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	1.5610%				358	358	358	358	358	358	358	358	358	358	358	358	4,296
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.8150%				(143)	187	187	187	187	187	187	187	187	187	187	187	1,914
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$1,575	$1,903	$1,900	$1,898	$1,896	$1,894	$1,890	$1,887	$1,885	$1,882	$1,881	$1,878	$22,369
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$1,575	$1,903	$1,900	$1,898	$1,896	$1,894	$1,890	$1,887	$1,885	$1,882	$1,881	$1,878	$22,369

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(C) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation			(57,087)	(57,471)	(57,855)	(58,239)	(58,623)	(59,007)	(59,391)	(59,775)	(60,159)	(60,543)	(60,927)	(61,311)	(61,695)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$141,901	$141,517	$141,133	$140,749	$140,365	$139,981	$139,597	$139,213	$138,829	$138,445	$138,061	$137,677	$137,293	
6	Average Net Investment				141,709	141,325	140,941	140,557	140,173	139,789	139,405	139,021	138,637	138,253	137,869	137,485	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		1.97%	1.89%	232	232	231	230	230	229	220	219	218	218	217	217	2,693
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%	674	672	670	668	666	665	670	669	667	665	663	661	8,010
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.3149%			384	384	384	384	384	384	384	384	384	384	384	384	4,608
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	1.1030%			(147)	183	183	183	183	183	183	183	183	183	183	183	1,866
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,143	$1,471	$1,468	$1,465	$1,463	$1,461	$1,457	$1,455	$1,452	$1,450	$1,447	$1,445	$17,177
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,143	$1,471	$1,468	$1,465	$1,463	$1,461	$1,457	$1,455	$1,452	$1,450	$1,447	$1,445	$17,177

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation			(32,655)	(32,874)	(33,093)	(33,312)	(33,531)	(33,750)	(33,969)	(34,188)	(34,407)	(34,626)	(34,845)	(35,064)	(35,283)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$55,012	$54,793	$54,574	$54,355	$54,136	$53,917	$53,698	$53,479	$53,260	$53,041	$52,822	$52,603	$52,384	
6	Average Net Investment				54,903	54,684	54,465	54,246	54,027	53,808	53,589	53,370	53,151	52,932	52,713	52,494	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		1.97%	1.89%	90	90	89	89	89	88	84	84	84	83	83	83	1,036
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%	261	260	259	258	257	256	258	257	256	255	253	252	3,082
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.0000%			219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.8220%			(270)	60	60	60	60	60	60	60	60	60	60	60	390
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$300	$629	$627	$626	$625	$623	$621	$620	$619	$617	$615	$614	$7,136
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$300	$629	$627	$626	$625	$623	$621	$620	$619	$617	$615	$614	$7,136

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation				0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (C)				239,885	219,894	199,904	179,914	159,923	139,933	119,942	99,952	79,962	59,971	39,981	19,990	0	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$239,885	$219,894	$199,904	$179,914	$159,923	$139,933	$119,942	$99,952	$79,962	$59,971	$39,981	$19,990	$0	
6	Average Net Investment					229,890	209,899	189,909	169,918	149,928	129,938	109,947	89,957	69,966	49,976	29,986	9,995	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		377	344	311	278	246	213	173	142	110	79	47	16	2,336
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		1,093	998	903	808	713	618	529	433	336	240	144	48	6,863
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	0.0000%				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (C)					19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	19,990	239,885
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.0000%				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$21,460	$21,332	$21,204	$21,076	$20,949	$20,821	$20,692	$20,565	$20,436	$20,309	$20,181	$20,054	$249,084
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$21,460	$21,332	$21,204	$21,076	$20,949	$20,821	$20,692	$20,565	$20,436	$20,309	$20,181	$20,054	$249,084

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation				(113,899)	(114,686)	(115,473)	(116,260)	(117,047)	(117,834)	(118,621)	(119,408)	(120,195)	(120,982)	(121,769)	(122,556)	(123,343)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$235,685	$234,898	$234,111	$233,324	$232,537	$231,750	$230,963	$230,176	$229,389	$228,602	$227,815	$227,028	$226,241	
6	Average Net Investment					235,291	234,504	233,717	232,930	232,143	231,356	230,569	229,782	228,995	228,208	227,421	226,634	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		386	384	383	382	380	379	363	362	361	360	358	357	4,455
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		1,119	1,115	1,111	1,108	1,104	1,100	1,109	1,105	1,101	1,097	1,094	1,090	13,253
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.7000%				787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.7220%				(120)	210	210	210	210	210	210	210	210	210	210	210	2,190
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$2,172	$2,496	$2,491	$2,487	$2,481	$2,476	$2,469	$2,464	$2,459	$2,454	$2,449	$2,444	$29,342
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$2,172	$2,496	$2,491	$2,487	$2,481	$2,476	$2,469	$2,464	$2,459	$2,454	$2,449	$2,444	$29,342

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.
(C) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation			($66,342)	(66,765)	(67,188)	(67,611)	(68,034)	(68,457)	(68,880)	(69,303)	(69,726)	(70,149)	(70,572)	(70,995)	(71,418)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$315,218	$314,795	$314,372	$313,949	$313,526	$313,103	$312,680	$312,257	$311,834	$311,411	$310,988	$310,565	$310,142	
6	Average Net Investment				315,006	314,583	314,160	313,737	313,314	312,891	312,468	312,045	311,622	311,199	310,776	310,353	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		1.97%	1.89%	516	516	515	514	513	513	492	492	491	490	490	489	6,031
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%	1,498	1,496	1,494	1,492	1,490	1,488	1,503	1,501	1,498	1,496	1,494	1,492	17,942
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.3299%			423	423	423	423	423	423	423	423	423	423	423	423	5,076
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.8390%			(63)	267	267	267	267	267	267	267	267	267	267	267	2,874
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,374	$2,702	$2,699	$2,696	$2,693	$2,691	$2,685	$2,683	$2,679	$2,676	$2,674	$2,671	$31,923
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$2,374	$2,702	$2,699	$2,696	$2,693	$2,691	$2,685	$2,683	$2,679	$2,676	$2,674	$2,671	$31,923

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	
3	Less: Accumulated Depreciation				($235,217)	(239,641)	(244,065)	(248,489)	(252,913)	(257,337)	(261,761)	(266,185)	(270,609)	(275,033)	(279,457)	(283,881)	(288,305)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$1,913,883	$1,909,459	$1,905,035	$1,900,611	$1,896,187	$1,891,763	$1,887,339	$1,882,915	$1,878,491	$1,874,067	$1,869,643	$1,865,219	$1,860,795	
6	Average Net Investment					1,911,671	1,907,247	1,902,823	1,898,399	1,893,975	1,889,551	1,885,127	1,880,703	1,876,279	1,871,855	1,867,431	1,863,007	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		3,133	3,126	3,119	3,111	3,104	3,097	2,971	2,964	2,957	2,950	2,943	2,936	36,411
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		9,090	9,069	9,048	9,027	9,005	8,984	9,065	9,044	9,022	9,001	8,980	8,959	108,294
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.4700%				4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.0525%				(317)	94	94	94	94	94	94	94	94	94	94	94	717
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$16,330	$16,713	$16,685	$16,656	$16,627	$16,599	$16,554	$16,526	$16,497	$16,469	$16,441	$16,413	$198,510
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$16,330	$16,713	$16,685	$16,656	$16,627	$16,599	$16,554	$16,526	$16,497	$16,469	$16,441	$16,413	$198,510

For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$159,014	($1,299)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$157,716
	b. Clearings to Plant					159,014	(1,299)	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$83,225,983	83,384,998	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	
3	Less: Accumulated Depreciation				($1,166,676)	(1,269,934)	(1,373,191)	(1,476,448)	(1,579,705)	(1,682,962)	(1,786,219)	(1,889,476)	(1,992,733)	(2,095,990)	(2,199,247)	(2,302,504)	(2,405,761)	
4	CWIP - Non-Interest Bearing				0	0	1	1	1	1	1	1	1	1	1	1	1	
5	Net Investment (Lines 2 + 3 + 4)				$82,059,307	$82,115,064	$82,010,508	$81,907,251	$81,803,994	$81,700,737	$81,597,480	$81,494,223	$81,390,966	$81,287,709	$81,184,452	$81,081,195	$80,977,938	
6	Average Net Investment					82,087,186	82,062,786	81,958,880	81,855,623	81,752,366	81,649,109	81,545,852	81,442,595	81,339,338	81,236,081	81,132,824	81,029,567	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		134,534	134,494	134,324	134,155	133,985	133,816	128,509	128,347	128,184	128,021	127,859	127,696	1,573,924
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		390,309	390,193	389,699	389,208	388,717	388,226	392,128	391,632	391,135	390,639	390,142	389,646	4,681,674
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	1.4860%				103,258	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	1,239,085
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.0525%				(12,318)	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	27,799
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$615,783	$631,591	$630,927	$630,267	$629,606	$628,946	$627,541	$626,883	$626,223	$625,564	$624,905	$624,246	$7,522,482
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$615,783	$631,591	$630,927	$630,267	$629,606	$628,946	$627,541	$626,883	$626,223	$625,564	$624,905	$624,246	$7,522,482

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2020 through December 2020
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4r) - CR4 Clinker Mitigation
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	
3	Less: Accumulated Depreciation				($104,197)	(105,558)	(106,919)	(108,280)	(109,641)	(111,002)	(112,363)	(113,724)	(115,085)	(116,446)	(117,807)	(119,168)	(120,529)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$556,801	$555,440	$554,079	$552,718	$551,357	$549,996	$548,635	$547,274	$545,913	$544,552	$543,191	$541,830	$540,469	
6	Average Net Investment					556,121	554,760	553,399	552,038	550,677	549,316	547,955	546,594	545,233	543,872	542,511	541,150	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		911	909	907	905	903	900	864	861	859	857	855	853	10,584
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		2,644	2,638	2,631	2,625	2,618	2,612	2,635	2,628	2,622	2,615	2,609	2,602	31,479
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.4700%				1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	16,332
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.0525%				(98)	29	29	29	29	29	29	29	29	29	29	29	221
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$4,818	$4,937	$4,928	$4,920	$4,911	$4,902	$4,889	$4,879	$4,871	$4,862	$4,854	$4,845	$58,616
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$4,818	$4,937	$4,928	$4,920	$4,911	$4,902	$4,889	$4,879	$4,871	$4,862	$4,854	$4,845	$58,616

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4s) - CR5 Clinker Mitigation
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant					0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements					0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other					0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base				$505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	
3	Less: Accumulated Depreciation				($66,823)	(67,864)	(68,905)	(69,946)	(70,987)	(72,028)	(73,069)	(74,110)	(75,151)	(76,192)	(77,233)	(78,274)	(79,315)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$439,081	$438,040	$436,999	$435,958	$434,917	$433,876	$432,835	$431,794	$430,753	$429,712	$428,671	$427,630	$426,589	
6	Return on Average Net Investment (A)					438,561	437,520	436,479	435,438	434,397	433,356	432,315	431,274	430,233	429,192	428,151	427,110	
7	Return on Average Net Investment		Jan-Jun	Jul-Dec														
	a. Debt Component		1.97%	1.89%		719	717	715	714	712	710	681	680	678	676	675	673	8,350
	b. Equity Component Grossed Up For Taxes		5.71%	5.77%		2,085	2,080	2,075	2,070	2,065	2,061	2,079	2,074	2,069	2,064	2,059	2,054	24,835
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	2.4700%				1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	12,492
	b. Amortization					0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (B)	0.0525%				(75)	22	22	22	22	22	22	22	22	22	22	22	167
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$3,770	$3,860	$3,853	$3,847	$3,840	$3,834	$3,823	$3,817	$3,810	$3,803	$3,797	$3,790	$45,844
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$3,770	$3,860	$3,853	$3,847	$3,840	$3,834	$3,823	$3,817	$3,810	$3,803	$3,797	$3,790	$45,844

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.
(B) January 2020 Property Tax includes a credit to revise prior period calculations which utilized an incorrect property tax rate; the credit includes applicable commercial paper interest.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Commission Forms 42-1P Through 42-8P

January 2021 - December 2021
Calculation of Projected Period Amount

Docket No. 20200007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 25
PARTY: CAM-5
DESCRIPTION: Forms 42-1P – 42-8PJanuary 2021 – December 2021

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2021 - December 2021

Line		Energy ($)	Transmission Demand ($)	Distribution Demand ($)	Production Demand ($)	Total ($)
1	Total Jurisdictional Rev Req for the Projected Period					
a	Projected O&M Activities (Form 42-2P, Lines 7 through 9)	$20,913,665	$2,106	$600	$281,889	$21,198,260
b	Projected Capital Projects (Form 42-3P, Lines 7 through 9)	20,120,846	0	1,003	3,404,938	23,526,787
c	Total Jurisdictional Rev Req for the Projected Period (Lines 1a + 1b)	41,034,511	2,106	1,603	3,686,827	44,725,047
2	True-up for Estimated Over/(Under) Recovery for the Current Period January 2020 - December 2020 (Form 42-2E, Line 5 + 6 + 10)	7,621,521	9,242	261	466,155	8,097,179
3	Final True-up for the Period January 2019 - December 2019 (Form 42-1A, Line 3)	(1,950,382)	89,390	153,970	(85,418)	(1,792,439)
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection Period January 2021 - December 2021 (Line 1 - Line 2 - Line 3)	35,363,372	(96,526)	(152,629)	3,306,090	38,420,307
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$35,388,833	($96,595)	($152,739)	$3,308,471	$38,447,970

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2021 - December 2021

O&M Activities
(in Dollars)

Line		Description	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1		O&M Activities - System													
	1	Transmission Substation Environmental Investigation, Remediation and Pollution Prevention	$500	$500	$500	$500	$500	$500	$0	$0	$0	$0	$0	$0	$3,000
	1a	Distribution Substation Environmental Investigation, Remediation and Pollution Prevention	0	0	0	0	0	0	0	0	0	0	0	0	0
	2	Distribution System Environmental Investigation, Remediation and Pollution Prevention	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	Above Ground Tank Secondary Containment - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	SO2/NOx Emissions Allowances - Energy	1,193	757	933	447	823	903	936	925	825	837	830	503	9,913
	6	Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	5,000	0	0	0	0	0	0	0	5,000
	6a	Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	5,000	0	0	0	0	0	25,000	0	30,000
	7.2	CAIR/CAMR - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.4	CAIR/CAMR Crystal River - Base	907,575	1,420,049	1,020,264	858,102	1,118,516	1,118,780	1,380,202	1,063,061	1,063,077	1,063,093	1,013,110	1,369,784	13,395,613
	7.4	CAIR/CAMR Crystal River - Energy	549,892	350,033	589,001	375,660	536,960	668,172	752,890	788,540	655,617	632,671	396,471	0	6,295,908
	7.4	CAIR/CAMR Crystal River - A&G	5,782	5,782	5,955	6,134	6,318	6,508	6,703	6,904	7,111	7,325	7,544	7,771	79,837
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	1,800,000
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	8	Arsenic Groundwater Standard - Base	57,500	52,500	52,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	275,000
	9	Sea Turtle - Coastal Street Lighting - Distrib	50	50	50	50	50	50	50	50	50	50	50	50	600
	11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15.1	Effluent Limitation Guidelines Program CRN - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	0	0	0	11,100	0	0	0	11,100	9,300	0	0	0	31,500
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	15,000	15,000	15,000	5,000	5,000	5,000	5,000	50,000	50,000	65,000	65,000	65,000	360,000
	17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	18	Coal Combustion Residual (CCR) Rule - Energy	23,167	23,167	23,167	23,167	23,167	23,167	23,167	23,167	23,167	23,167	23,167	23,167	278,000
2		Total O&M Activities - Recoverable Costs	$1,710,659	$2,017,838	$1,857,370	$1,442,660	$1,863,834	$1,985,580	$2,331,448	$2,106,247	$1,971,646	$1,954,642	$1,693,672	$1,628,775	$22,564,371
3		Recoverable Costs Allocated to Energy	739,252	538,956	778,101	565,374	715,950	847,242	931,993	1,023,732	888,909	871,674	635,468	238,670	8,775,321
4		Recoverable Costs Allocated to Demand - Transm	500	500	500	500	500	500	0	0	0	0	0	0	3,000
		Recoverable Costs Allocated to Demand - Distrib	50	50	50	50	50	50	50	50	50	50	50	50	600
		Recoverable Costs Allocated to Demand - Prod-Base	965,075	1,472,549	1,072,764	870,602	1,136,016	1,131,280	1,392,702	1,075,561	1,075,577	1,075,593	1,025,610	1,382,284	13,675,613
		Recoverable Costs Allocated to Demand - Prod-Intm	0	0	0	0	5,000	0	0	0	0	0	25,000	0	30,000
		Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0
		Recoverable Costs Allocated to Demand - A&G	5,782	5,782	5,955	6,134	6,318	6,508	6,703	6,904	7,111	7,325	7,544	7,771	79,837
5		Retail Energy Jurisdictional Factor	0.97503	0.97243	0.95780	0.96021	0.93736	0.94660	0.95548	0.95489	0.95419	0.95287	0.96318	0.97081	
6		Retail Transmission Demand Jurisdictional Factor	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	0.70203	
		Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
		Retail Production Demand Jurisdictional Factor - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
		Retail Production Demand Jurisdictional Factor - Intm	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
		Retail Production Demand Jurisdictional Factor - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
		Retail Production Demand Jurisdictional Factor - A&G	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	
7		Jurisdictional Energy Recoverable Costs (A)	720,789	524,100	745,261	542,875	671,102	801,995	890,500	977,550	848,184	830,594	612,072	231,703	8,396,725
8		Jurisdictional Demand Recoverable Costs - Transm (B)	351	351	351	351	351	351	0	0	0	0	0	0	2,106
		Jurisdictional Demand Recoverable Costs - Distrib (B)	50	50	50	50	50	50	50	50	50	50	50	50	600
		Jurisdictional Demand Recoverable Costs - Prod-Base (B)	896,410	1,367,777	996,437	808,658	1,055,188	1,050,790	1,293,611	999,035	999,049	999,065	952,638	1,283,934	12,702,592
		Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	0	0	0	0	3,635	0	0	0	0	0	18,176	0	21,811
		Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	0	0	0	0	0	0	0	0	0	0	0
		Jurisdictional Demand Recoverable Costs - A&G (B)	5,390	5,390	5,552	5,718	5,890	6,067	6,249	6,436	6,629	6,828	7,033	7,244	74,426
9		Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8)	$1,622,990	$1,897,668	$1,747,651	$1,357,652	$1,736,216	$1,859,253	$2,190,410	$1,983,071	$1,853,912	$1,836,537	$1,589,969	$1,522,931	$21,198,260

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2021 - December 2021

Capital Investment Projects-Recoverable Costs
(in Dollars)

Form 42-3P

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)

Line	Description	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investment Projects - System (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.1	Above Ground Tank Secondary Containment - Peaking	69,849	69,646	69,440	69,234	69,030	68,826	68,621	68,416	68,213	62,574	62,405	62,234	808,489
4.2	Above Ground Tank Secondary Containment - Base	18,470	18,450	18,431	18,412	18,392	18,373	18,354	18,335	18,315	18,296	18,276	18,257	220,361
4.3	Above Ground Tank Secondary Containment - Intm	1,990	1,986	1,982	1,980	1,976	1,972	1,969	1,965	1,962	1,959	1,955	1,951	23,647
5	SO2/NOX Emissions Allowances - Energy	21,282	21,275	21,270	21,265	21,261	21,256	21,249	21,243	21,238	21,232	21,227	21,222	255,020
6	Phase II Cooling Water Intake 316(b) - Base	90,259	90,166	90,071	89,977	89,884	89,790	89,697	89,603	89,510	89,416	89,322	89,229	1,076,924
6.1	Phase II Cooling Water Intake 316(b) - Base - Bartow	0	0	0	0	0	0	0	0	0	0	0	0	0
6.2	Phase II Cooling Water Intake 316(b) - Intermediate - Anclote	0	0	0	0	0	0	0	0	0	0	0	0	0
7.1	CAIR/CAMR Anclote- Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	18,490	18,418	18,346	18,274	18,200	18,132	18,058	17,985	17,913	9,112	9,098	9,084	191,111
7.3	CAMR Crystal River - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
7.4	CAIR/CAMR Crystal River AFUDC - Base	666,833	666,107	665,380	664,654	663,925	663,200	662,472	661,747	661,019	660,291	659,565	658,838	7,954,031
7.4	CAIR/CAMR Crystal River AFUDC - Energy	3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	41,106
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Sea Turtle - Coastal Street Lighting -Distrib	82	82	82	83	83	85	85	85	85	85	85	85	1,007
10.1	Underground Storage Tanks - Base	1,181	1,179	1,177	1,175	1,173	1,171	1,169	1,167	1,166	1,163	1,162	1,159	14,042
10.2	Underground Storage Tanks - Intm	543	542	540	539	538	536	535	534	532	531	530	528	6,428
11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
11.1	Crystal River Thermal Discharge Compliance Project - Base (Post 2012)	0	0	0	0	0	0	0	0	0	0	0	0	0
11.1	Crystal River Thermal Discharge Compliance Project - Base (2012)	0	0	0	0	0	0	0	0	0	0	0	0	0
15.1	Effluent Limitation Guidelines CRN (ELG) - Base	22,830	22,794	22,758	22,721	22,686	22,650	22,613	22,577	22,541	22,505	22,469	22,433	271,577
16	National Pollutant Discharge Elimination System (NPDES) - Intm	112,079	111,842	111,607	111,372	111,136	110,900	110,665	110,429	110,194	109,959	109,722	109,487	1,329,392
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	27,683	27,640	27,596	27,553	27,508	27,465	27,422	27,378	27,335	27,291	27,248	27,204	329,327
17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion -	1,047,848	1,046,247	1,044,647	1,043,046	1,041,446	1,039,845	1,038,245	1,036,645	1,035,044	1,033,444	1,031,842	1,030,242	12,468,535
17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Coal Combustion Residual (CCR) Rule - Base	12,568	12,837	13,107	13,377	13,647	16,854	16,968	16,943	16,918	16,894	16,870	16,846	183,829
2	Total Investment Projects - Recoverable Costs	$2,115,413	$2,112,637	$2,109,860	$2,107,088	$2,104,311	$2,104,481	$2,101,548	$2,098,478	$2,095,411	$2,078,177	$2,075,201	$2,072,224	$25,174,826
3	Recoverable Costs Allocated to Energy	1,100,238	1,098,587	1,096,938	1,095,289	1,093,640	1,091,991	1,090,341	1,088,691	1,087,042	1,085,392	1,083,742	1,082,093	13,093,989
	Recoverable Costs Allocated to Distribution Demand	82	82	82	83	83	85	85	85	85	85	85	85	1,007
4	Recoverable Costs Allocated to Demand - Production - Base	812,141	811,533	810,924	810,316	809,707	812,038	811,273	810,372	809,469	808,565	807,664	806,762	9,720,764
	Recoverable Costs Allocated to Demand - Production - Intermediate	114,612	114,370	114,129	113,891	113,650	113,408	113,169	112,928	112,688	112,449	112,207	111,966	1,359,467
	Recoverable Costs Allocated to Demand - Production - Peaking	88,339	88,064	87,786	87,508	87,230	86,958	86,679	86,401	86,126	71,686	71,503	71,318	999,600
5	Retail Energy Jurisdictional Factor	0.97503	0.97243	0.95780	0.96021	0.93736	0.94660	0.95548	0.95489	0.95419	0.95287	0.96318	0.97081	
	Retail Distribution Demand Jurisdictional Factor	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
6	Retail Demand Jurisdictional Factor - Production - Base	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
7	Jurisdictional Energy Recoverable Costs (B)	1,072,761	1,068,305	1,050,643	1,051,703	1,025,133	1,033,674	1,041,799	1,039,578	1,037,241	1,034,240	1,043,842	1,050,505	12,549,423
	Jurisdictional Demand Recoverable Costs - Distribution (B)	82	82	82	83	83	85	85	85	85	85	85	85	1,003
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	754,357	753,792	753,227	752,662	752,096	754,261	753,551	752,714	751,875	751,036	750,199	749,361	9,029,132
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	83,326	83,150	82,975	82,802	82,627	82,451	82,277	82,102	81,928	81,754	81,578	81,403	988,373
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	84,738	84,475	84,208	83,941	83,675	83,414	83,146	82,879	82,616	68,764	68,589	68,411	958,856
9	Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8)	$1,995,265	$1,989,804	$1,971,134	$1,971,191	$1,943,614	$1,953,885	$1,960,858	$1,957,358	$1,953,744	$1,935,878	$1,944,292	$1,949,764	$23,526,787

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9; Form 42-4P, Line 5 for Projects 5 - Emission Allowances and Project 7. 4 - Reagents.
(B) Line 3 x Line 5
(C) Line 4 x Line 6

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Peaking (Project 4.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements (G)			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	$8,661,298	
3	Less: Accumulated Depreciation		(3,722,267)	(3,747,843)	(3,773,419)	(3,798,995)	(3,824,571)	(3,850,147)	(3,875,723)	(3,901,299)	(3,926,875)	(3,952,451)	(3,978,027)	(4,003,603)	(4,029,179)	
3a	Regulatory Asset Balance (G)		$49,060	$43,609	$38,158	$32,707	$27,256	$21,804	$16,353	$10,902	$5,451	$0	$0	$0	$0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$4,988,091	$4,957,063	$4,926,036	$4,895,009	$4,863,982	$4,832,955	$4,801,928	$4,770,901	$4,739,874	$4,708,847	$4,683,271	$4,657,695	$4,632,119	
6	Average Net Investment			$4,972,577	$4,941,550	$4,910,523	$4,879,496	$4,848,469	$4,817,442	$4,786,414	$4,755,387	$4,724,360	$4,696,059	$4,670,483	$4,644,907	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		7,571	7,524	7,476	7,428	7,382	7,335	7,288	7,241	7,194	7,151	7,111	7,072	87,773
	b. Equity Component Grossed Up For Taxes	6.10%		25,259	25,103	24,945	24,787	24,629	24,472	24,314	24,156	24,000	23,855	23,726	23,594	292,840
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	25,576	306,912
	b. Amortization (G)			5,451	5,451	5,451	5,451	5,451	5,451	5,451	5,451	5,451	0	0	0	49,060
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	5,992	71,904
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$69,849	$69,646	$69,440	$69,234	$69,030	$68,826	$68,621	$68,416	$68,213	$62,574	$62,405	$62,234	$808,489
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$69,849	$69,646	$69,440	$69,234	$69,030	$68,826	$68,621	$68,416	$68,213	$62,574	$62,405	$62,234	$808,489
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			67,002	66,807	66,610	66,412	66,216	66,021	65,824	65,627	65,433	60,023	59,861	59,697	775,535
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$67,002	$66,807	$66,610	$66,412	$66,216	$66,021	$65,824	$65,627	$65,433	$60,023	$59,861	$59,697	$775,535

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Project 4.1d to be amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	$2,365,947	
3	Less: Accumulated Depreciation		(59,908)	(62,838)	(65,768)	(68,698)	(71,628)	(74,558)	(77,488)	(80,418)	(83,348)	(86,278)	(89,208)	(92,138)	(95,068)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,306,039	$2,303,109	$2,300,179	$2,297,249	$2,294,319	$2,291,389	$2,288,459	$2,285,529	$2,282,599	$2,279,669	$2,276,739	$2,273,809	$2,270,879	
6	Average Net Investment			$2,304,574	$2,301,644	$2,298,714	$2,295,784	$2,292,854	$2,289,924	$2,286,994	$2,284,064	$2,281,134	$2,278,204	$2,275,274	$2,272,344	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		3,509	3,504	3,500	3,496	3,491	3,487	3,482	3,478	3,473	3,469	3,464	3,460	41,813
	b. Equity Component Grossed Up For Taxes	6.10%		11,707	11,692	11,677	11,662	11,647	11,632	11,618	11,603	11,588	11,573	11,558	11,543	139,500
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	35,160
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			324	324	324	324	324	324	324	324	324	324	324	324	3,888
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$18,470	$18,450	$18,431	$18,412	$18,392	$18,373	$18,354	$18,335	$18,315	$18,296	$18,276	$18,257	$220,361
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$18,470	$18,450	$18,431	$18,412	$18,392	$18,373	$18,354	$18,335	$18,315	$18,296	$18,276	$18,257	$220,361
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			17,156	17,137	17,120	17,102	17,083	17,066	17,048	17,030	17,012	16,994	16,976	16,958	204,682
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$17,156	$17,137	$17,120	$17,102	$17,083	$17,066	$17,048	$17,030	$17,012	$16,994	$16,976	$16,958	$204,682

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297		
3	Less: Accumulated Depreciation		($91,686)	(92,211)	(92,736)	(93,261)	(93,786)	(94,311)	(94,836)	(95,361)	(95,886)	(96,411)	(96,936)	(97,461)	(97,986)			
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	0		
5	Net Investment (Lines 2+ 3 + 4)		$198,611	$198,086	$197,561	$197,036	$196,511	$195,986	$195,461	$194,936	$194,411	$193,886	$193,361	$192,836	$192,311			
6	Average Net Investment			$198,349	$197,824	$197,299	$196,774	$196,249	$195,724	$195,199	$194,674	$194,149	$193,624	$193,099	$192,574			
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		302	301	300	300	299	298	297	296	296	295	294	293	3,571		
	b. Equity Component Grossed Up For Taxes	6.10%		1,008	1,005	1,002	1,000	997	994	992	989	986	984	981	978	11,916		
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0		
8	Investment Expenses															
	a. Depreciation (C)			525	525	525	525	525	525	525	525	525	525	525	525	6,300		
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0		
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
	d. Property Taxes (D)			155	155	155	155	155	155	155	155	155	155	155	155	1,860		
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0		
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,990	$1,986	$1,982	$1,980	$1,976	$1,972	$1,969	$1,965	$1,962	$1,959	$1,955	$1,951	$23,647		
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0		
	b. Recoverable Costs Allocated to Demand			$1,990	$1,986	$1,982	$1,980	$1,976	$1,972	$1,969	$1,965	$1,962	$1,959	$1,955	$1,951	$23,647		
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703			
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
13	Retail Demand-Related Recoverable Costs (F)			1,447	1,444	1,441	1,440	1,437	1,434	1,432	1,429	1,426	1,424	1,421	1,418	17,192		
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,447	$1,444	$1,441	$1,440	$1,437	$1,434	$1,432	$1,429	$1,426	$1,424	$1,421	$1,418	$17,192		

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Working Capital Dr (Cr)															
	a. 0158150 SO_2 Emission Allowance Inventory		$3,223,685	$3,222,773	$3,222,016	$3,221,083	$3,220,636	$3,219,813	$3,218,910	$3,217,973	$3,217,048	$3,216,223	$3,215,387	$3,214,557	$3,214,053	$3,214,053
	b. 0254020 Auctioned SO_2 Allowance		$281	0	0	0	0	0	0	0	0	0	0	0	0	0
	c. 0158170 NOx Emission Allowance Inventory		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Working Capital		$3,223,966	$3,222,773	$3,222,016	$3,221,083	$3,220,636	$3,219,813	$3,218,910	$3,217,973	$3,217,048	$3,216,223	$3,215,387	$3,214,557	$3,214,053	$3,214,053
3	Average Net Investment			$3,223,369	$3,222,395	$3,221,550	$3,220,860	$3,220,224	$3,219,361	$3,218,442	$3,217,511	$3,216,636	$3,215,805	$3,214,972	$3,214,305	
4	Return on Average Net Working Capital Balance (B)															
	a. Debt Component	1.83%		4,908	4,906	4,905	4,904	4,903	4,902	4,900	4,899	4,898	4,896	4,895	4,894	58,810
	b. Equity Component Grossed Up For Taxes	6.10%		16,374	16,369	16,365	16,361	16,358	16,354	16,349	16,344	16,340	16,336	16,332	16,328	196,210
5	Total Return Component (C)			$21,282	$21,275	$21,270	$21,265	$21,261	$21,256	$21,249	$21,243	$21,238	$21,232	$21,227	$21,222	255,020
6	Expense Dr (Cr)															
	a. 0509030 SO_2 Allowance Expense			$912	$757	$933	$447	$823	$903	$936	$925	$825	$837	$830	$503	9,632
	b. 0407426 Amortization Expense			281	0	0	0	0	0	0	0	0	0	0	0	0
	c. 0 509212 NOx Allowance Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (D)			1,193	757	933	447	823	903	936	925	825	837	830	503	9,913
8	Total System Recoverable Expenses (Lines 5 + 7)			$22,475	$22,032	$22,203	$21,712	$22,084	$22,159	$22,185	$22,168	$22,063	$22,069	$22,057	$21,725	264,933
	a. Recoverable costs allocated to Energy			$22,475	$22,032	$22,203	$21,712	$22,084	$22,159	$22,185	$22,168	$22,063	$22,069	$22,057	$21,725	264,933
	b. Recoverable costs allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
9	Energy Jurisdictional Factor			0.97503	0.97243	0.95780	0.96021	0.93736	0.94660	0.95548	0.95489	0.95419	0.95287	0.96318	0.97081	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (E)			$21,913	$21,425	$21,266	$20,848	$20,701	$20,975	$21,198	$21,168	$21,052	$21,029	$21,245	$21,091	253,911
12	Retail Demand-Related Recoverable Costs (F)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 21,913	$ 21,425	$ 21,266	$ 20,848	$ 20,701	$ 20,975	$ 21,198	$ 21,168	$ 21,052	$ 21,029	$ 21,245	$ 21,091	$ 253,911

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 5 is reported on Capital Schedule
(D) Line 7 is reported on O&M Schedule
(E) Line 8a x Line 9
(F) Line 8b x Line 10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Base (Project 6)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			11,453,608	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	11,453,608	11,453,608	11,453,608	11,453,608	11,453,608	11,453,608	11,453,608	11,453,608	11,453,608	11,453,608	11,453,608	11,453,608	
3	Less: Accumulated Depreciation		0	(14,183)	(28,366)	(42,549)	(56,732)	(70,915)	(85,098)	(99,281)	(113,464)	(127,647)	(141,830)	(156,013)	(170,196)	
4	CWIP - Non-Interest Bearing		11,453,608	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$11,453,608	$11,439,425	$11,425,242	$11,411,059	$11,396,876	$11,382,693	$11,368,510	$11,354,327	$11,340,144	$11,325,961	$11,311,778	$11,297,595	$11,283,412	
6	Average Net Investment			$11,446,517	$11,432,334	$11,418,151	$11,403,968	$11,389,785	$11,375,602	$11,361,419	$11,347,236	$11,333,053	$11,318,870	$11,304,687	$11,290,504	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		17,428	17,407	17,385	17,363	17,342	17,320	17,299	17,277	17,256	17,234	17,212	17,191	207,714
	b. Equity Component Grossed Up For Taxes	6.10%		58,147	58,075	58,002	57,930	57,858	57,786	57,714	57,642	57,570	57,498	57,426	57,354	693,002
	c. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	1.4860%		14,183	14,183	14,183	14,183	14,183	14,183	14,183	14,183	14,183	14,183	14,183	14,183	170,196
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000525		501	501	501	501	501	501	501	501	501	501	501	501	6,012
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$90,259	$90,166	$90,071	$89,977	$89,884	$89,790	$89,697	$89,603	$89,510	$89,416	$89,322	$89,229	1,076,924
	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			90,259	90,166	90,071	89,977	89,884	89,790	89,697	89,603	89,510	89,416	89,322	89,229	1,076,924
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			83,837	83,751	83,662	83,575	83,489	83,401	83,315	83,228	83,141	83,054	82,967	82,880	1,000,300
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$83,837	$83,751	$83,662	$83,575	$83,489	$83,401	$83,315	$83,228	$83,141	$83,054	$82,967	$82,880	$1,000,300

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Base - Bartow (Project 6.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes	6.10%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	1.4860%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000525		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Phase II Cooling Water Intake 316(b) - Intermediate - Anclote (Project 6.2)
(in Dollars)

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
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Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6	Average Net Investment			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Equity Component Grossed Up For Taxes	6.10%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	1.4860%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.006390		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements (G)			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	$1,293,144	
3	Less: Accumulated Depreciation		($358,483)	(360,654)	(362,825)	(364,996)	(367,167)	(369,338)	(371,509)	(373,680)	(375,851)	(378,022)	(380,193)	(382,364)	(384,535)	
3a	Regulatory Asset Balance (G)		$78,814	70,057	61,300	52,543	43,785	35,028	26,271	17,514	8,757	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,013,475	$1,002,547	$991,619	$980,691	$969,762	$958,834	$947,906	$936,978	$926,050	$915,122	$912,951	$910,780	$908,609	
6	Average Net Investment			$1,008,011	$997,083	$986,155	$975,227	$964,298	$953,370	$942,442	$931,514	$920,586	$914,037	$911,866	$909,695	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		1,535	1,518	1,502	1,485	1,467	1,453	1,435	1,418	1,402	1,391	1,388	1,385	17,379
	b. Equity Component Grossed Up For Taxes	6.10%		5,120	5,065	5,009	4,954	4,898	4,844	4,788	4,732	4,676	4,643	4,632	4,621	57,982
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	2,171	26,052
	b. Amortization (G)			8,757	8,757	8,757	8,757	8,757	8,757	8,757	8,757	8,757	0	0	0	78,814
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			907	907	907	907	907	907	907	907	907	907	907	907	10,884
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$18,490	$18,418	$18,346	$18,274	$18,200	$18,132	$18,058	$17,985	$17,913	$9,112	$9,098	$9,084	191,111
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$18,490	$18,418	$18,346	$18,274	$18,200	$18,132	$18,058	$17,985	$17,913	$9,112	$9,098	$9,084	191,111
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	0.95924	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			17,736	17,667	17,598	17,529	17,458	17,393	17,322	17,252	17,183	8,741	8,727	8,714	183,321
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$17,736	$17,667	$17,598	$17,529	$17,458	$17,393	$17,322	$17,252	$17,183	$8,741	$8,727	$8,714	$183,321

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Projects 7.2a and 7.2e to be amortized over one year in accordance with petition filed 8/30/2019 in Docket 20190007-EI

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	$86,699,701	
3	Less: Accumulated Depreciation		($2,893,910)	($3,003,993)	($3,114,076)	($3,224,159)	($3,334,242)	($3,444,325)	($3,554,408)	($3,664,491)	($3,774,574)	($3,884,657)	($3,994,740)	($4,104,823)	($4,214,906)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$83,805,791	$83,695,708	$83,585,625	$83,475,542	$83,365,459	$83,255,376	$83,145,293	$83,035,210	$82,925,127	$82,815,044	$82,704,961	$82,594,878	$82,484,795	
6	Average Net Investment			$83,750,750	$83,640,667	$83,530,584	$83,420,501	$83,310,418	$83,200,335	$83,090,252	$82,980,169	$82,870,086	$82,760,003	$82,649,920	$82,539,837	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		127,518	127,350	127,183	127,015	126,847	126,680	126,511	126,345	126,176	126,008	125,841	125,674	1,519,148
	b. Equity Component Grossed Up For Taxes	6.10%		425,440	424,882	424,322	423,764	423,203	422,645	422,086	421,527	420,968	420,408	419,849	419,289	5,068,383
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	110,083	1,320,996
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	3,792	45,504
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$666,833	$666,107	$665,380	$664,654	$663,925	$663,200	$662,472	$661,747	$661,019	$660,291	$659,565	$658,838	7,954,031
	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			$666,833	$666,107	$665,380	$664,654	$663,925	$663,200	$662,472	$661,747	$661,019	$660,291	$659,565	$658,838	7,954,031
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			619,388	618,713	618,038	617,364	616,687	616,013	615,337	614,664	613,987	613,311	612,637	611,962	7,388,102
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$619,388	$618,713	$618,038	$617,364	$616,687	$616,013	$615,337	$614,664	$613,987	$613,311	$612,637	$611,962	$7,388,102

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Depreciation calculated in CAIR Crystal River section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Property taxes calculated in CAIR Crystal River section of Capital Program Detail file only on assets in-service. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
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Schedule of Amortization and Return
For Project: CAIR/CAMR - Energy (Project 7.4 - Reagents and By-Products)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Working Capital Dr (Cr)															
	a. 0154401 Ammonia Inventory		$572,877	$572,877	$572,877	$572,877	$572,877	$572,877	$572,877	$572,877	$572,877	$572,877	$572,877	$572,877	$572,877	572,877
	b. 0154200 Limestone Inventory		($54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)	(54,050)
2	Total Working Capital		$518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827
3	Average Net Investment			518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	518,827	
4	Return on Average Net Working Capital Balance (A)															
	a. Debt Component	1.83%		790	790	790	790	790	790	790	790	790	790	790	790	$9,479
	b. Equity Component Grossed Up For Taxes	6.10%		2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	31,627
5	Total Return Component (B)			3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	3,426	41,106
6																
	a. 0502010 Ammonia Expense			117,700	41,100	136,900	116,500	130,700	186,800	226,500	246,100	193,000	177,800	51,200	0	1,624,300
	b. 0502040 Limestone Expense			375,741	310,026	380,751	182,058	333,801	365,186	378,296	377,226	337,531	343,140	340,933	0	3,724,689
	c. 0502050 Dibasic Acid Expense			900	300	1,100	900	1,000	1,500	1,700	1,900	1,500	1,400	400	0	12,600
	d. 0502070 Gypsum Disposal/Sale			(43,249)	(35,893)	(44,250)	(21,198)	(39,041)	(42,814)	(44,406)	(43,885)	(39,114)	(39,669)	(39,362)	0	(432,881)
	e. 0502040 Hydrated Lime Expense			98,800	34,500	114,500	97,400	110,500	157,500	190,800	207,200	162,700	150,000	43,300	0	1,367,200
	f. 0502300 Caustic Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			549,892	350,033	589,001	375,660	536,960	668,172	752,890	788,540	655,617	632,671	396,471	0	6,295,908
8	Total System Recoverable Expenses (Lines 5 + 7)			$553,318	$353,458	$592,427	$379,086	$540,385	$671,598	$756,315	$791,966	$659,043	$636,096	$399,897	$3,426	$6,337,015
	a. Recoverable Costs Allocated to Energy			553,318	353,458	592,427	379,086	540,385	671,598	756,315	791,966	659,043	636,096	399,897	3,426	6,337,015
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Energy Jurisdictional Factor			0.97503	0.97243	0.95780	0.96021	0.93736	0.94660	0.95548	0.95489	0.95419	0.95287	0.96318	0.97081	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			539,499	343,715	567,423	364,000	506,535	635,731	722,644	756,239	628,849	606,119	385,174	3,326	6,059,254
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 539,499	$ 343,715	$ 567,423	$ 364,000	$ 506,535	$ 635,731	$ 722,644	$ 756,239	$ 628,849	$ 606,119	$ 385,174	$ 3,326	$ 6,059,254

Notes:

(A) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50	$600
	b. Clearings to Plant			50	50	50	50	50	50	50	50	50	50	50	50	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$11,324	11,374	11,424	11,474	11,524	11,574	11,624	11,674	11,724	11,774	11,824	11,874	11,924	
3	Less: Accumulated Depreciation		(4,394)	(4,423)	(4,452)	(4,481)	(4,510)	(4,539)	(4,569)	(4,599)	(4,629)	(4,659)	(4,689)	(4,719)	(4,749)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$6,930	$6,951	$6,972	$6,993	$7,014	$7,035	$7,055	$7,075	$7,095	$7,115	$7,135	$7,155	$7,175	
6	Average Net Investment			$6,941	$6,962	$6,983	$7,004	$7,025	$7,045	$7,065	$7,085	$7,105	$7,125	$7,145	$7,165	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		11	11	11	11	11	11	11	11	11	11	11	11	132
	b. Equity Component Grossed Up For Taxes	6.10%		35	35	35	36	36	36	36	36	36	36	36	36	429
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.0658%		29	29	29	29	29	30	30	30	30	30	30	30	355
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007755		7	7	7	7	7	8	8	8	8	8	8	8	91
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$82	$82	$82	$83	$83	$85	$85	$85	$85	$85	$85	$85	1,007
	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			$82	$82	$82	$83	$83	$85	$85	$85	$85	$85	$85	$85	1,007
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)			0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	0.99561	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			82	82	82	83	83	85	85	85	85	85	85	85	1,003
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$82	$82	$82	$83	$83	$85	$85	$85	$85	$85	$85	$85	$1,003

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 2 x rate x 1/12. Depreciation Rate based on 2010 Rate Case Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Base (Project 10.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation		(53,104)	(53,400)	(53,696)	(53,992)	(54,288)	(54,584)	(54,880)	(55,176)	(55,472)	(55,768)	(56,064)	(56,360)	(56,656)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$115,837	$115,541	$115,245	$114,949	$114,653	$114,357	$114,061	$113,765	$113,469	$113,173	$112,877	$112,581	$112,285	
6	Average Net Investment			$115,689	$115,393	$115,097	$114,801	$114,505	$114,209	$113,913	$113,617	$113,321	$113,025	$112,729	$112,433	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		176	176	175	175	174	174	173	173	173	172	172	171	2,084
	b. Equity Component Grossed Up For Taxes	6.10%		588	586	585	583	582	580	579	577	576	574	573	571	6,954
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.1000%		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.008573		121	121	121	121	121	121	121	121	121	121	121	121	1,452
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,181	$1,179	$1,177	$1,175	$1,173	$1,171	$1,169	$1,167	$1,166	$1,163	$1,162	$1,159	14,042
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,181	$1,179	$1,177	$1,175	$1,173	$1,171	$1,169	$1,167	$1,166	$1,163	$1,162	$1,159	14,042
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			1,097	1,095	1,093	1,091	1,090	1,088	1,086	1,084	1,083	1,080	1,079	1,077	13,043
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,097	$1,095	$1,093	$1,091	$1,090	$1,088	$1,086	$1,084	$1,083	$1,080	$1,079	$1,077	$13,043

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Duke Energy Florida, LLC
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DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
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Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation		(33,965)	(34,168)	(34,371)	(34,574)	(34,777)	(34,980)	(35,183)	(35,386)	(35,589)	(35,792)	(35,995)	(36,198)	(36,401)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$42,041	$41,838	$41,635	$41,432	$41,229	$41,026	$40,823	$40,620	$40,417	$40,214	$40,011	$39,808	$39,605	
6	Average Net Investment			$41,940	$41,737	$41,534	$41,331	$41,128	$40,925	$40,722	$40,519	$40,316	$40,113	$39,910	$39,707	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		64	64	63	63	63	62	62	62	61	61	61	60	746
	b. Equity Component Grossed Up For Taxes	6.10%		213	212	211	210	209	208	207	206	205	204	203	202	2,490
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.2000%		203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Tax (D)	0.009890		63	63	63	63	63	63	63	63	63	63	63	63	756
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$543	$542	$540	$539	$538	$536	$535	$534	$532	$531	$530	$528	6,428
	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			$543	$542	$540	$539	$538	$536	$535	$534	$532	$531	$530	$528	6,428
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			395	394	393	392	391	390	389	388	387	386	385	384	4,673
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$395	$394	$393	$392	$391	$390	$389	$388	$387	$386	$385	$384	$4,673

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
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Duke Energy Florida, LLC
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Return on Capital Investments, Depreciation and Taxes
For Project: Effluent Limitation Guidelines CRN - Base (Project 15.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	2,658,112	
3	Less: Accumulated Depreciation		(43,735)	(49,206)	(54,677)	(60,148)	(65,619)	(71,090)	(76,561)	(82,032)	(87,503)	(92,974)	(98,445)	(103,916)	(109,387)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,614,377	$2,608,906	$2,603,435	$2,597,964	$2,592,493	$2,587,022	$2,581,551	$2,576,080	$2,570,609	$2,565,138	$2,559,667	$2,554,196	$2,548,725	
6	Average Net Investment			$2,611,641	$2,606,170	$2,600,699	$2,595,228	$2,589,757	$2,584,286	$2,578,815	$2,573,344	$2,567,873	$2,562,402	$2,556,931	$2,551,460	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		3,976	3,968	3,960	3,951	3,943	3,935	3,926	3,918	3,910	3,901	3,893	3,885	47,166
	b. Equity Component Grossed Up For Taxes	6.10%		13,267	13,239	13,211	13,183	13,156	13,128	13,100	13,072	13,044	13,017	12,989	12,961	157,367
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.4700%		5,471	5,471	5,471	5,471	5,471	5,471	5,471	5,471	5,471	5,471	5,471	5,471	65,652
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000525		116	116	116	116	116	116	116	116	116	116	116	116	1,392
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$22,830	$22,794	$22,758	$22,721	$22,686	$22,650	$22,613	$22,577	$22,541	$22,505	$22,469	$22,433	271,577
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			22,830	22,794	22,758	22,721	22,686	22,650	22,613	22,577	22,541	22,505	22,469	22,433	271,577
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			21,206	21,172	21,139	21,104	21,072	21,038	21,004	20,971	20,937	20,904	20,870	20,837	252,254
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$21,206	$21,172	$21,139	$21,104	$21,072	$21,038	$21,004	$20,971	$20,937	$20,904	$20,870	$20,837	$252,254

Notes:

(A) N/A

(B)
Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
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Duke Energy Florida, LLC
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Return on Capital Investments, Depreciation and Taxes
For Project: NPDES - Intermediate (Project 16)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	12,841,870	
3	Less: Accumulated Depreciation		(2,572,638)	(2,608,310)	(2,643,982)	(2,679,654)	(2,715,326)	(2,750,998)	(2,786,670)	(2,822,342)	(2,858,014)	(2,893,686)	(2,929,358)	(2,965,030)	(3,000,702)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$10,269,232	$10,233,560	$10,197,888	$10,162,216	$10,126,544	$10,090,872	$10,055,200	$10,019,528	$9,983,856	$9,948,184	$9,912,512	$9,876,840	$9,841,168	
6	Average Net Investment			$10,251,396	$10,215,724	$10,180,052	$10,144,380	$10,108,708	$10,073,036	$10,037,364	$10,001,692	$9,966,020	$9,930,348	$9,894,676	$9,859,004	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		15,609	15,554	15,500	15,446	15,391	15,337	15,283	15,228	15,174	15,120	15,065	15,011	183,718
	b. Equity Component Grossed Up For Taxes	6.10%		52,076	51,894	51,713	51,532	51,351	51,169	50,988	50,807	50,626	50,445	50,263	50,082	612,946
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.333%		35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	35,672	428,064
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.008150		8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	8,722	104,664
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$112,079	$111,842	$111,607	$111,372	$111,136	$110,900	$110,665	$110,429	$110,194	$109,959	$109,722	$109,487	1,329,392
	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			$112,079	$111,842	$111,607	$111,372	$111,136	$110,900	$110,665	$110,429	$110,194	$109,959	$109,722	$109,487	1,329,392
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	0.72703	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			81,485	81,312	81,142	80,971	80,799	80,628	80,457	80,285	80,114	79,943	79,771	79,600	966,508
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$81,485	$81,312	$81,142	$80,971	$80,799	$80,628	$80,457	$80,285	$80,114	$79,943	$79,771	$79,600	$966,508

Notes:

(A) N/A

(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.

(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.

(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 4 & 5 - Energy (Project 17)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	3,690,187	
3	Less: Accumulated Depreciation		(424,949)	(431,531)	(438,113)	(444,695)	(451,277)	(457,859)	(464,441)	(471,023)	(477,605)	(484,187)	(490,769)	(497,351)	(503,933)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$3,265,238	$3,258,656	$3,252,074	$3,245,492	$3,238,910	$3,232,328	$3,225,746	$3,219,164	$3,212,582	$3,206,000	$3,199,418	$3,192,836	$3,186,254	
6	Average Net Investment			$3,261,947	$3,255,365	$3,248,783	$3,242,201	$3,235,619	$3,229,037	$3,222,455	$3,215,873	$3,209,291	$3,202,709	$3,196,127	$3,189,545	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		4,967	4,957	4,947	4,937	4,926	4,916	4,906	4,896	4,886	4,876	4,866	4,856	58,936
	b. Equity Component Grossed Up For Taxes	6.10%		16,570	16,537	16,503	16,470	16,436	16,403	16,370	16,336	16,303	16,269	16,236	16,202	196,635
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	Blended		6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	6,582	78,984
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000525		161	161	161	161	161	161	161	161	161	161	161	161	1,932
	e. Other (E)			(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(597)	(7,160)
9	Total System Recoverable Expenses (Lines 7 + 8)			$27,683	$27,640	$27,596	$27,553	$27,508	$27,465	$27,422	$27,378	$27,335	$27,291	$27,248	$27,204	329,327
	a. Recoverable Costs Allocated to Energy			27,683	27,640	27,596	27,553	27,508	27,465	27,422	27,378	27,335	27,291	27,248	27,204	329,327
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.97503	0.97243	0.95780	0.96021	0.93736	0.94660	0.95548	0.95489	0.95419	0.95287	0.96318	0.97081	
11	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)			$26,992	$26,878	$26,432	$26,457	$25,785	$25,999	$26,202	$26,143	$26,083	$26,005	$26,245	$26,410	$315,631
13	Retail Demand-Related Recoverable Costs (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$26,992	$26,878	$26,432	$26,457	$25,785	$25,999	$26,202	$26,143	$26,083	$26,005	$26,245	$26,410	$315,631

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: MERCURY & AIR TOXIC STANDARDS (MATS) - ANCLOTE GAS CONVERSION - Energy (Project 17.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	133,918,267	
3	Less: Accumulated Depreciation		(20,366,566)	(20,608,980)	(20,851,394)	(21,093,808)	(21,336,222)	(21,578,636)	(21,821,050)	(22,063,464)	(22,305,878)	(22,548,292)	(22,790,706)	(23,033,120)	(23,275,534)	
4	CWIP - AFUDC Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$113,551,701	$113,309,287	$113,066,873	$112,824,459	$112,582,045	$112,339,631	$112,097,217	$111,854,803	$111,612,389	$111,369,975	$111,127,561	$110,885,147	$110,642,733	
6	Average Net Investment			$113,430,494	$113,188,080	$112,945,666	$112,703,252	$112,460,838	$112,218,424	$111,976,010	$111,733,596	$111,491,182	$111,248,768	$111,006,354	$110,763,940	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		172,707	172,338	171,969	171,600	171,231	170,862	170,493	170,124	169,755	169,386	169,016	168,647	2,048,128
	b. Equity Component Grossed Up For Taxes	6.10%		576,210	574,978	573,747	572,515	571,284	570,052	568,821	567,590	566,358	565,127	563,895	562,664	6,833,241
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.1722%		242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	242,414	2,908,968
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.006390		71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	71,311	855,732
	e. Other (E)			(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(14,794)	(177,534)
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,047,848	$1,046,247	$1,044,647	$1,043,046	$1,041,446	$1,039,845	$1,038,245	$1,036,645	$1,035,044	$1,033,444	$1,031,842	$1,030,242	12,468,535
	a. Recoverable Costs Allocated to Energy			1,047,848	1,046,247	1,044,647	1,043,046	1,041,446	1,039,845	1,038,245	1,036,645	1,035,044	1,033,444	1,031,842	1,030,242	12,468,535
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.97503	0.97243	0.95780	0.96021	0.93736	0.94660	0.95548	0.95489	0.95419	0.95287	0.96318	0.97081	
11	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
12	Retail Energy-Related Recoverable Costs (F)			$1,021,678	$1,017,407	$1,000,558	$1,001,538	$976,208	$984,312	$992,022	$989,879	$987,624	$984,739	$993,852	$1,000,167	$11,949,984
13	Retail Demand-Related Recoverable Costs (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,021,678	$1,017,407	$1,000,558	$1,001,538	$976,208	$984,312	$992,022	$989,879	$987,624	$984,739	$993,852	$1,000,167	$11,949,984

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Return on Capital Investments, Depreciation and Taxes
For Project: COAL COMBUSTION RESIDUAL (CCR) RULE - Base (Project 18)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$41,667	$41,667	$41,667	$41,667	$41,667	$41,667	$0	$0	$0	$0	$0	$0	$250,000
	b. Clearings to Plant			0	0	0	0	0	1,591,780	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$446,090	446,090	446,090	446,090	446,090	446,090	2,037,870	2,037,870	2,037,870	2,037,870	2,037,870	2,037,870	2,037,870	
3	Less: Accumulated Depreciation (A)		($29,924)	(30,730)	(31,536)	(32,342)	(33,148)	(33,954)	(37,638)	(41,322)	(45,006)	(48,690)	(52,374)	(56,058)	(59,742)	
4	CWIP - Non-Interest Bearing		1,341,780	1,383,447	1,425,113	1,466,780	1,508,447	1,550,113	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,757,946	$1,798,807	$1,839,668	$1,880,528	$1,921,389	$1,962,250	$2,000,232	$1,996,548	$1,992,864	$1,989,180	$1,985,496	$1,981,812	$1,978,128	
6	Average Net Investment			$1,778,377	$1,819,237	$1,860,098	$1,900,959	$1,941,819	$1,981,241	$1,998,390	$1,994,706	$1,991,022	$1,987,338	$1,983,654	$1,979,970	
7	Return on Average Net Investment (B)															
	a. Debt Component	1.83%		2,708	2,770	2,832	2,894	2,957	3,017	3,043	3,037	3,031	3,026	3,020	3,015	35,350
	b. Equity Component Grossed Up For Taxes	6.10%		9,034	9,241	9,449	9,657	9,864	10,064	10,152	10,133	10,114	10,095	10,077	10,058	117,938
	c. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.1695%		806	806	806	806	806	3,684	3,684	3,684	3,684	3,684	3,684	3,684	29,818
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.000525		20	20	20	20	20	89	89	89	89	89	89	89	723
	e. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$12,568	$12,837	$13,107	$13,377	$13,647	$16,854	$16,968	$16,943	$16,918	$16,894	$16,870	$16,846	183,829
	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			12,568	12,837	13,107	13,377	13,647	16,854	16,968	16,943	16,918	16,894	16,870	16,846	183,829
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)			11,674	11,924	12,174	12,425	12,676	15,655	15,761	15,738	15,714	15,692	15,670	15,647	170,750
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$11,674	$11,924	$12,174	$12,425	$12,676	$15,655	$15,761	$15,738	$15,714	$15,692	$15,670	$15,647	$170,750

Notes:

(A) N/A
(B) Line 6 x 7.92% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.60% and statutory income tax rate of 24.522% (inc tax multiplier = 1.3248894). See Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-2010-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2019 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Project Title: **Substation Environmental Investigation, Remediation and Pollution Prevention**
Project No. 1

Project Description:
Chapter 376 Florida Statutes requires that any person discharging a prohibited pollutant shall undertake to contain, remove and abate the discharge to the satisfaction of the FDEP. Similarly, Chapter 403 Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For DEF to comply with these statutes, it is actively conducting remediation and pollution prevention activities at its substation sites to remove the existence of pollutant discharges. Activities also include development and implementation of best management and pollution prevention measures at these sites.

Project Accomplishments:
The remediation portion of the Substation Assessment and Remedial Action Plan has been completed for all of the 279 SARAP substation sites. The Amended Deed Restrictive Covenant ("DRC") for West Lake Wales Substation has been approved by FDEP. The proposed DRC for Central Florida Substation submitted for approval to FDEP in July 2020.

Project Fiscal Expenditures:
2020 O&M expenditures for the substation system program (Projects 1 & 1a) are estimated to be $13k. Project 1, Transmission Substation Remediation, is forecasted to be $13k. Project 1a, Distribution Substation Remediation, is forecasted to be $157. The distribution portion of this program is now complete.

Project Progress Summary:
DEF continues to provide documentation for FDEP approval for the Substation Assessment and Remedial Action Plan (SARAP) and the Consent Order.

Project Projections:
2021 O&M estimated expenditures are $3,000.

Project Title: **Distribution System Environmental Investigation, Remediation and Pollution Prevention**
Project No. 2

Project Description:
Chapter 376 Florida Statutes requires that any person discharging a prohibited pollutant shall undertake to contain, remove and abate the discharge to the satisfaction of the FDEP. Similarly, Chapter 403 Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For DEF to comply with these statutes, it is actively conducting remediation and pollution prevention activities at its distribution sites to remove the existence of pollutant discharges. Activities also include development and implementation of best management and pollution prevention measures at these sites.

Project Accomplishments:
All TRIP sites source removals are completed. The Final TRIP has been completed and the NAM report submitted to FDEP 4-4-19.

Project Fiscal Expenditures:
No further charges are expected to hit this project in 2020

Project Progress Summary:
This project is complete.

Project Projections:
No further charges are expected to hit this project in 2021.

Project Title: **Pipeline Integrity Management (PIM) - Bartow/Anclote Pipeline**
Project No. 3

Project Description:
The U.S. Department of Transportation (USDOT) Regulation 49 CFR Part 195, as amended effective 2/15/02, and the new regulation published at 67 Federal Register 2136 on 1/16/02, requires DEF to implement a PIM program. Prior to the 2/15/02 amendments, the USDOT's PIM regulations applied only to operators with 500 miles or more of hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on 2/15/02, extended the requirements for implementing integrity management to operators who have less than 500 miles of regulated pipelines. As such, DEF must maintain the integrity of pipeline systems in order to protect public safety and the environment, and comply with continual assessment and evaluation of pipeline systems integrity through inspection or testing, data integration and analysis, and follow up with remedial, preventative, and mitigative actions. DEF owns one hazardous liquid pipeline, Bartow/Anclote 14-inch hot oil pipeline, extending 33.3 miles from the Company's Bartow Plant north of St. Petersburg to the Anclote Plant in Holiday, that is subject to PIM regulations.

Effective 2/2010, amendments to 49 CFR 195 were finalized to improve opportunities to reduce risk through more effective control of pipelines. Compliance with these amendments will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue management. On 6/16/11, the USDOT published in the Federal Register (V0l. 76, 35130-35136), a final rule effective 8/15/11, that expedites the program implementation deadlines in the Control Room Management/Human Factors regulations in order to realize the safety benefits sooner than established in the original rule. This final rule amends the program implementation deadlines for different procedures to no later than 10/21/11 and 8/1/12.

Project Accomplishments:
Since the Bartow Anclote Pipeline (BAP) contained a small quantity of #6 fuel oil, the PIM program under 49CFR195 continues to be maintained. Third party projects by Florida Department of Transportation (FDOT), Florida Gas Transmission, Pinellas County, The City of Pinellas Park, and others have been evaluated for their risk to BAP integrity. Risk mitigation measures have been completed per 49CFR195.450. The BAP Risk Analysis has been updated. The Annual Report and National Pipeline Mapping System (NPMS) annual review have been completed. Reviews and evaluations are also being completed for Advisory Bulletins 11-04, 13-02, 15-01, and 15-02, relating to flooding and hurricanes. BAP personnel have participated in US Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA), utility owners groups, damage prevention groups, and FDOT workshops and training. Pipeline accidents and PHMSA enforcement actions have been reviewed for conditions that are applicable to the BAP and appropriate changes to BAP practices and procedures have been implemented. Pipeline records are being organized and stored with the conversion to electronic storage now essentially complete.

In 2016, pipeline ownership was transferred from the Fossil Hydro Operations group to Plant Retirement and Demolition, in preparation for pipeline retirement that is expected to occur in 2016. Once retired, the pipeline will be cleaned to remove any remaining oil. Once cleaned, the requirements described above in the PIM program will no longer be required. Cleaning is expected to occur in 2016, with any required demolition activities in 2017. As of the end of 2016, three of the four sub-projects were retired and approved to be amortized over three years - Project 3.1b Pipeline Leak Detection, Project 3.1c Pipeline Controls Upgrade, and Project 3.1d Control Room Management.

The final sub-project 3.1a - Alderman Road Fence was retired June 2017 and approved as a regulatory asset. This was amortized over 26 months, and all four parts of this project are fully amortized as of September 2019.

Project Fiscal Expenditures:
No capital or O&M expenditures are estimated for 2020.

Project Progress Summary:
Projects 3.1b (Pipeline leak Detection), 3.1c (Pipeline Controls Upgrade), and 3.1d (Control Room Management) were retired August 2016. Project 3.1a (Alderman Road Fence) retired June 2017. All are fully amortized as of September 2019.

Project Projections:
No capital or O&M expenditures are estimated for 2021.

Project Title: **Above Ground Storage Tank Secondary Containment**
Project No. 4

Project Description:
FDEP Rule 62-761.510(3) states that DEF is required to make improvements to its above ground petroleum storage tanks in order to comply with those provisions. Subsection (d) of the rule requires all internally lined single bottom above ground storage tanks to be upgraded with secondary containment, including secondary containment for piping in contact with the soil. Rule 62-761.500(1)(e) also requires that dike field area containment for pre-1998 tanks be upgraded, if needed, to comply with the requirement.

Project Accomplishments:
DEF has completed work at Debary 1 and 2, Turner 7, Turner 8, Higgins 1, and Bartow 6 as well as Turner P-1 and P-2 piping work.

Project Fiscal Expenditures:
No project expenditures are expected in 2020.

Project Progress Summary:
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications. Project 4.1a (Turner CTs) retired in March 2016.

Project Projections:
No new project expenditures are expected in 2021. DEF retired the Higgins combustion turbine plant December 2019, and expects to retire the Avon Park plant in 2020. With this retirement, the Above Ground Tank Secondary Containment and CAIR CT assets will also be retired. Consistent with Order No. PSC-2019-0500-FOF-EI, DEF is treating the unrecovered investments as a regulatory asset, and will amortize them over one year until fully recovered, with a return on the unamortized balance.

Project Title: **SO_2 and NOx Emissions Allowances**
Project No. 5

Project Description:
In accordance with the Acid Rain Program in Title IV of the Clean Air Act, CFR 40 Part 73 and Part 76, Florida Administrative Code Rule 62-214 and the Clean Air Interstate Rule (CAIR), DEF manages sulfur dioxide (SO_2) and nitrogen oxide (NOx) allowance inventory to offset emissions. On 7/6/11, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to replace the CAIR. The CSAPR significantly alters SO_2 and NOx allowance programs. Under the CAIR, Florida has to comply with annual SO_2 and NOx emission requirements, and seasonal NOx emission requirements. Under the CSAPR, Florida is no longer required to comply with annual emissions requirements, only ozone seasonal limits. On 8/8/11, the final CSAPR was published in the Federal Register. The CSAPR sets state-level annual and seasonal SO_2 and NOx emission allowance requirements effective 1/1/12.

On 8/21/12, the D.C. Circuit Court vacated the CSAPR. It also directed the EPA to continue administering the CAIR which requires additional reductions in SO_2 and NOx emissions beginning in 2015. On 4/29/14, the U.S. Supreme Court reversed the D.C. Circuit Court decision finding that with CSAPR the EPA reasonably interpreted the good neighbor provision of the Clean Air Act. The case was then remanded to the D.C. Circuit Court for further proceedings, and the EPA requested the court lift the CSAPR stay and direct it to take effect on 1/1/15. On 10/23/14 the D.C. Circuit Court lifted the CSAPR stay. On 1/1/15, the CSAPR replaced the CAIR. The CSAPR took effect in Florida on 5/1/15. Consequently, CAIR NOx emission allowances have no value; however, SO2 emission allowances can continue to be used to comply with the Acid Rain Program. DEF treated its unused NOx costs as a regulatory asset amortizing it over 3 years, as approved by the Commission in Order No. PSC-2011-0553-FOF-EI. These are fully recovered as of December 2017.

Project Accomplishments:
Air quality compliance costs are administered by an authorized account representative who evaluates a variety of resources and options. Activities performed include purchases of SO2 and NOx emissions allowances as well as auctions and transfers of SO2 emissions allowances.

Project Fiscal Expenditures:
2020 O&M is forecasted to be $3.5k.

Project Progress Summary:
DEF continually evaluates the status of emission rules to maximize the cost effectiveness of its compliance strategy.

Project Projections:
2021 O&M expenditures are projected to be $10k.

Project Title: **Phase II Cooling Water Intake**
Project No. 6

Project Description:
Section 316(b) of the Federal Clean Water Act requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. 33 U.S.C. Section 1326. On 5/19/14, the EPA Administrator signed a final 316(b) rule to protect fish and aquatic life drawn into cooling systems at power plant and factories. The rule aims to minimize impingement (aquatic life pinned against cooling water intake structures) and entrainment (aquatic life drawn into cooling water systems). The regulation became effective on October 14, 2014, 60 days after publication in the Federal Register which was 8/15/14.

EPA's regulation implementing §316(b) of the Clean Water Act for existing facilities was published on August 15, 2014. The regulation aims to minimize adverse environmental impacts to fish and other aquatic organisms from the operation of cooling water intake structures. The regulation became effective October 14, 2014, 60 days after publication in the Federal Register. The regulation primarily applies to existing power generating facilities that commenced construction prior to or on January 17, 2002 and to new units at existing facilities that are built to increase the generating capacity of the facility.

According to the current 316(b) rule, required studies and information submittals will be due with the renewal of the NPDES permit application for permits that expire after July 18, 2018. Permittees with a current NPDES permit that expires before July 18, 2018 may request the FDEP establish an alternative schedule for submitting the required information. This rule is applicable to Anclote, Bartow, Suwannee, and Crystal River North stations.

Project Accomplishments:
DEF is currently evaluating the 316(b) rule to determine potential study requirements, operating and cost impacts to its generating stations. Site specific strategic plans, studies, and implementation plans are under development to ensure compliance with all applicable requirements of the rule.

Project Fiscal Expenditures:
2020 O&M expenditures are estimated to be $305k. 2020 Capital expenditures are estimated to be $5.8M.

Project Progress Summary:
Required 316(b) reports have been finalized and will be submitted with the NPDES permit renewal applications to FDEP for review and approval . Anclote & Bartow reports have been filed with FDEP. Capital work at CRN continues with the addition of two CRN intake pumps, traveling screens and screen wash system, and intake structure modifications.

Project Projections:
2021 estimated O&M expenditures are $35k.

Project Title: **Integrated Clean Air Compliance Plan - Clean Air Interstate Rule (CAIR)**
Project Nos. (7.2, 7.3 & 7.4)

Project Description:
The Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant restrictions on emissions of SO_2 and NOx from power plants in 28 eastern states, including Florida and the District of Columbia. The CAIR rule apportions region-wide SO_2 and NOx emission reduction requirements to the individual states, and further requires each affected state to revise its State Implementation Plans (SIPs) to include measures necessary to achieve its emission reduction budget within prescribed deadlines.

The Cross-State air pollution Rule (CSAPR) replaced CAIR on 1/1/15. Under the CSAPR, the State of Florida is no longer required to comply with annual emission requirements, only NOx ozone seasonal limits. The CSAPR requirements took effect in Florida on 5/1/15, the beginning of the ozone season. NOx emission allowances under CAIR have no value; however, DEF will continue to use its SO2 emission allowances to comply with the Acid Rain Program. (see Project No. 5 - SO2 and NOx Emission Allowances Project Sheet for more information).

The Florida Department of Environmental Protection ("FDEP") Conditions of Certification, dated August 1, 2012, require DEF to evaluate an alternative disposal method of FGD Blowdown wastewater based on results of groundwater monitoring near percolation ponds. DEF is installing a physical/chemical treatment system to treat FGD Blowdown wastewater with discharge to surface water or percolation ponds.

Project Accomplishments:
The FGD Wastewater treatment (WWT) system went in-service February 2019.

Project Fiscal Expenditures:
For 2020, O&M expenditures for CAIR/CAMR – Peaking (Project 7.2) are projected to be $0. For the CAIR/CAMR Crystal River Program (Project 7.4), O&M is forecasted be $16.3M. Capital expenditures are forecasted to be $158k.

Project Progress Summary:
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

Project Projections:
2021 estimated O&M expenditures are $22.1M.

Project Title: **Best Available Retrofit Technology (BART)**
Project No. 7.5

Project Description:
On 5/25/12, the EPA proposed a partial disapproval of Florida's proposed Regional Haze State Implementation Plan (SIP) because the proposed SIP relies on CAIR to satisfy BART requirements for SO_2 and NOx emissions. CAIR remained in effect while litigation against the Cross State Air Pollution Rule (CSAPR) proceeded, and the EPA incorporated the CSAPR in place of CAIR into Regional Haze SIPs, including Florida. DEF worked with the FDEP to develop specific BART and Reasonable Progress permits for affected units that were incorporated into Florida's revised SIP submittal, which was filed with EPA on 9/17/12. The final BART permit applications for Crystal River fossil units were submitted to EPA on 10/15/12 as a supplement to the 9/17/12 submittal. Permitting was finalized in 2013 with an effective date of January 1, 2014.

Project Accomplishments:
DEF performed required emissions modeling and associated BART analysis for Crystal River 1&2 (CR1&2) and Anclote plants, developed and submitted a Reasonable Progress evaluation for Crystal River 4&5, developed and submitted necessary BART Implementation Plans and air construction permit applications in support of the FDEP's work to amend its SIP as directed by the EPA. Permitting actions were completed in 2013 with the effective date of the CR 1& 2 permit being January 1, 2014.

Project Fiscal Expenditures:
No project expenditures are expected in 2020.

Project Progress Summary:
DEF performed required emissions modeling and associated BART analysis for CR1&2 and Anclote, developed and submitted a Reasonable Progress evaluation for Crystal River 4&5, developed and submitted necessary BART Implementation Plans and air construction permit applications needed in support of the FDEP ongoing work to amend its State Implementation Plan as directed by the EPA. Based on the revised Regional Haze SIP incorporating the provisions of Crystal River's BART permits for SO_2 and NOx, EPA on 12/10/12 proposed approval of the SIP. In August 2013, EPA finalized the full approval of the SIP. The Crystal River South BART permit became effective on January 1, 2014 and DEF is now operating under the terms of that permit.

Project Projections:
No project expenditures are expected in 2021.

Project Title: **Arsenic Groundwater Standard**
Project No. 8

Project Description:
On 12/22/01, the EPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water replacing the previous standard of 0.050 mg/L (50 ppb) with a new MCL of 0.010 mg/L (10 ppb). Effective 1/1/05, the FDEP established the USEPA MCL as Florida's drinking water standard. See Rule 62-550 F.A.C. The new standard has compliance implications for land application and water reuse projects in Florida with arsenic ground water monitoring levels above 10 ppb because the drinking water standard has been established as the groundwater standard by Rule 62-520-420(1), F.A.C.

Project Accomplishments:
A Plan of Study (POS) to evaluate the source of arsenic at the site was implemented on November 2011. A POS Addendum that included a leachability study and proposed abandoning one well and installing 3 new wells was implemented in February 2012. An additional Flue Gas Desulfurization (FGD) Wastewater Treatment Study was conducted in May 2013. The results of these studies indicated that Arsenic is naturally occurring in some areas but there is also a contribution from the FGD discharge from the lined treatment pond to the percolation ponds, and from the industrial wastewater from Crystal River Units 1 & 2. These sources are being addressed by the construction of a new FGD wastewater treatment system and retirement of Units 1 & 2, both scheduled to be completed by December 31, 2018.
Additional assessment was initiated in 2016 around the area of ground water wells still exceeding the Arsenic standard of 10 ppb with no clear source of Arsenic identified (MWC-1, MWC-31 and MWC-32). This additional assessment indicated that the source of Arsenic around MWC-31 is related to the former North Ash Pond that was located in that area. Based on that finding, the Consent Order was amended to address that area under 62-780, F.A.C. Remedial Actions, which included additional assessment and submittal of a final assessment report to FDEP in 2018.
Results from MWC-1 assessment indicate that the well is not measuring impacts from the industrial wastewater activities at the site and DEF requested to FDEP that the well be replaced by one of the Plan of Study wells. FDEP requested the sampling of all the wells around MWC-1 for a year prior to approval of the change. Assessment around MWC-32 is on-going in 2019.

Project Fiscal Expenditures:
2020 O&M expenditures are expected to be $1.2M.

Project Progress Summary:
Corrective actions are being implemented based on previous and continuing plan of studies.

Project Projections:
2021 O&M expenditures are forecasted to be $275k.

Project Title: **Sea Turtle - Coastal Street Lighting**
Project No. 9

Project Description:
DEF owns and leases high pressure sodium streetlights throughout its service territory, including areas along the Florida coast. Pursuant to Section 161.163, Florida Statutes, the FDEP, in collaboration with the Florida Fish and Wildlife Conservation Commission (FFWCC) and the U.S. Fish & Wildlife Service (USFWS), has developed a model Sea Turtle lighting ordinance. The model ordinance is used by the local governments to develop and implement ordinances within its jurisdiction. To date, Sea Turtle lighting ordinances have been adopted in Franklin County, Gulf County, City of Mexico Beach in Bay County and Pinellas County, all of which are within DEF's service territory. Since 2004, officials from the various local governments, as well as the FDEP, FFWC, and USFWS, have advised DEF that lighting it owns and leases is affecting turtle nesting areas that fall within the scope of these ordinances. As a result, local governments require DEF to take additional measures to satisfy new criteria being applied to ensure compliance with the sea turtle ordinances.

Project Accomplishments:
DEF continues to work with Franklin County, Gulf County, City of Mexico Beach in Bay County, and Pinellas County to mitigate any potential sea turtle nesting issues by retrofitting existing street lights, placing amber shields on existing HPS street lights and monitoring street lights for effectiveness in complying with sea turtle ordinances.

Project Fiscal Expenditures:
2020 Capital expenditures are estimated to be $0, O&M expenditures are estimated to be a $0.

Project Progress Summary:
DEF is on schedule with activities identified for this program.

Project Projections:
2021 estimated O&M is $600, and Capital expenditures are estimated at $600.

Project Title: **Underground Storage Tanks**
Project No. 10

Project Description:
FDEP regulations require that underground pollutant storage tanks and small diameter piping be upgraded with secondary containment by 12/31/09. See Rule 62-761.510(5), F.A.C. DEF identified four tanks that must comply with this rule: two at Crystal River Plant and two at Bartow Plant.

Project Accomplishments:
Work on Crystal River and Bartow USTs was completed in 4th Qtr 2006.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Modular Cooling Towers**
Project No. 11

Project Description:
This project involves installation and operation of modular cooling towers in the summer months to minimize de-rates of Crystal River 1&2 (CR1&2) necessary to comply with the NPDES permit limit for the temperature of cooling water discharged from the units.

Project Accomplishments:
Vendors of modular cooling towers were evaluated regarding cost of installation and operation. The FDEP reviewed the project and approved operation. A vendor was selected and the towers were installed during the 2nd Qtr 2006.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
The modular cooling towers began operation in June 2006 and successfully minimized de-rates of CR 1&2. The towers were removed during the first half of 2012. This project is complete.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Crystal River Thermal Discharge Compliance Project**
Project No. 11.1

Project Description:
This project was to evaluate and implement the best long term solution to maintain compliance with the thermal discharge limit in the FDEP industrial wastewater permit for Crystal River Units 1,2&3 that was being addressed in the short term by the Modular Cooling Towers approved in Docket No. 20060162-EI. Due to DEF's decision to retire CR3, this project is no longer necessary and will not be implemented.

Project Accomplishments:
The study phase of the project was completed with a recommendation to replace the leased modular cooling towers in coordination with the cooling solution for the CR3 Extended Power Uprate (EPU) discharge canal cooling solution. The new cooling tower associated with the CR3 EPU was to be sized to mitigate both increased temperatures from the EPU as well as replace the modular cooling towers, which were removed in 2012. The design contract for the CR3 EPU cooling tower was awarded and a vendor selected. In February 2013, DEF decided to retire CR3; therefore, the project will not proceed.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
Crystal River Units 1,2&3 utilize a once-through cooling water process to cool and condense turbine exhaust steam back to water. The cooling water is removed from the Gulf of Mexico via an intake canal and discharged to a common discharge canal shared by all of the generating units. DEF has a NPDES industrial wastewater permit from the FDEP to discharge this cooling water from CR 1,2&3 into the Gulf of Mexico. The FDEP NPDES permit includes a limit on the temperature of the cooling water discharge (96.5 degrees Fahrenheit on a three-hour rolling average) measured at the point of discharge to the Gulf of Mexico. The new cooling towers were being added as a long term solution to the issue of higher ambient water temperatures previously being addressed by the modular cooling towers and added heat rejection due to the estimated 180MW Uprate of CR3. With the retirement of CR3, the heat rejection associated with the entire unit is removed and therefore the new cooling tower is not necessary for the continued operation of CR 1&2 within the NPDES permit limits.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Greenhouse Gas (GHG) Inventory and Reporting**
Project No. 12

Project Description:
The GHG Inventory and Reporting Program was created in response to Chapter 2008-277, Florida Laws, which established the Florida Climate Protection Act to be codified at section 403.44, Florida Statutes. Among other things, this legislation authorizes the FDEP to establish a cap and trade program for GHG emissions from power plants. Utilities subject to the program, including DEF, will be required to use The Climate Registry for purposes of GHG emission registration and reporting. The requirement to report to The Climate Registry was repealed during the 2010 legislative session; however, the EPA GHG Reporting Rule (40 CFR 98) does require DEF to submit 2010 GHG data to the EPA no later than 9/30/2011.

Project Accomplishments:
In 2009, DEF joined The Climate Registry and submitted 2008 GHG inventory data. 2009 data was submitted during the third quarter of 2010. Both 2008 and 2009 data was validated by a third party as required by The Climate Registry. 2010 GHG inventory data was submitted to EPA on 9/30/11 and EPA does not require data validation by a third party. DEF has discontinued its membership with The Climate Registry. Since third party validation is not required by the EPA, no future expenditures will be incurred by DEF, resulting in the completion of this project.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
DEF submits GHG inventory data directly to EPA which does not require third party validation. Membership with The Climate Registry has been discontinued.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Mercury Total Daily Maximum Loads Monitoring (TMDL)**
Project No. 13

Project Description:
Section 303(d) of the Federal Clean Water Act requires each state to identify state waters not meeting water quality standards and establish a TMDL for the pollutant or pollutants causing the failure to meet standards. Under a 1999 federal consent decree, TMDLs for over 100 Florida water bodies listed as impaired for mercury must be established by 9/12/12. The FDEP has initiated a research program to provide necessary information for setting appropriate TMDLs for mercury. Among other things, the study will assess the relative contributions of mercury-emitting sources, such as coal-fired power plants, to mercury levels in surface waters.

Project Accomplishments:
Atmospheric & Environmental Research, Inc (AER) completed the literature review on mercury deposition in Florida. This document was sent to the FDEP Division of Air Resource Management and the TMDL team for review in February 2009. In addition, the Florida Electric Power Coordinating Group (FCG) Mercury Task Force met with FDEP Division of Air Resource Management to discuss the review in January 2010. AER performed Florida mercury deposition modeling for the Division of Air Resource Management. The FCG Mercury Task Force contracted with Tetra Tech to conduct aquatic field sampling, including an aquatics modeling report, to develop a "Conceptual Model for the Florida Mercury TMDL." This document was finalized and submitted to the FDEP in December 2010. Key personnel from AER were employed by Environ in 2011 and FCG established a contract with Environ to ensure continuity of the project. FCG used Environ and Tetra Tech to review and critique FDEP's aquatic cycling and atmospheric modeling analyses. The FDEP developed a mercury TMDL report in the spring and summer of 2012, and it proposed a TMDL in September 2012. The EPA approved Florida's statewide mercury TMDL in a letter dated October 18, 2013. Florida's mercury TMDL covers 441 waters listed as impaired for mercury based on fish tissue mercury levels. EPA's approval letter states that if FDEP identifies any new waters to be listed as impaired for mercury, a new TMDL will not be required if the listing is caused by the factors addressed in the approved TMDL. Conversely, a new TMDL, addressing the newly listed water body, would be required if "local emission or effluent sources" are determined to be the cause of the elevated fish tissue levels that required the new listing.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
The mercury TMDL study concluded in 2012.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Hazardous Air Pollutants (HAPs) ICR Program**
Project No. 14

Project Description:
In 2009, the EPA initiated efforts to develop an Information Collection Request (ICR), which requires that owners/operators of all coal- and oil-fired electric utility steam generating units provide information that will allow the EPA to assess emissions of hazardous air pollutants from each such unit. The intention of the ICR is to assist the Administrator of the EPA in developing national emission standards for hazardous air pollutants under Section 112(d) of the Clean Air Act, 42 U.S.C. 7412. Pursuant to those efforts, by letter dated 12/24/09, the EPA formally requested DEF comply with certain data collection and emissions testing requirements for several of its steam electric generating units. The EPA letter states that initial submittal of existing information must be made within 90 days, and that the remaining data must be submitted within 8 months. Collection and submittal of the requested information is mandatory under Section 114 of the Clean Air Act, 42 U.S.C. 7414.

Project Accomplishments:
DEF completed and submitted the ICR to EPA during 2010. The HAPS ICR project is complete.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA during 2010.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Effluent Limitation Guidelines ICR Program**
Project No. 15

Project Description:
The Effluent Limitation Guidelines ICR Program was created in response to Section 304 of the Federal Clean Water Act which directs the EPA to develop and periodically review regulations, called effluent guidelines, to limit the amount of pollutants that are discharged to surface waters from various point source categories. 33 U.S.C. §13 14(b). In October 2009, the EPA announced that it intended to update the effluent guidelines for the steam electric power generating point source category, which were last updated in 1982. DEF is required to complete the ICR and submit responses to the EPA within 90 days. Collection and submittal of the requested information is mandatory under Section 308 of the Clean Water Act.

Project Accomplishments:
DEF completed and submitted the ICR to the EPA in September 2010. The Effluent Limitation Guidelines ICR Program is complete.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA in September 2010.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Effluent Limitation Guidelines CRN Program**
Project No. 15.1

Project Description:
On September 30th, 2015, U.S. Environmental Protection Agency finalized the Steam Electric Power Generating Effluent Guidelines, 40 CFR Part 423, imposing federal standards on several power plant streams that are discharged to surface water. In the final regulation, closed-loop systems or dry handling have been identified as the Best Available Technology ("BAT") for bottom ash transport water. Crystal River North Units 4 & 5 have a dry bottom ash system that utilizes dewatering bins for separation of bottom ash and water. However, the current configuration has the potential for bottom ash transport water to leave via overflows and drain into an NPDES internal outfall. Achieving the closed loop bottom ash compliance requirement is as soon as possible beginning November 1, 2018 but no later than December 31, 2023. Renewal of the Crystal River Units 4 & 5 NPDES permit is in progress and addresses this requirement. Duke Energy is seeking a compliance date of February 1, 2020 to include modification of the existing system.

Project Accomplishments:
DEF Initiated the first phase of ELG compliance activities necessary to comply with NPDES permit renewal. The remaining project scope is still on hold pending EPA Administrative Stay final decision.

Project Fiscal Expenditures:
The 2020 Capital forecast is $231k.

Project Progress Summary:
This project was placed in-service June 2020.

Project Projections:
No capital or O&M expenditures are forecasted for 2021.

Project Title: **National Pollutant Discharge Elimination System (NPDES)**
Project No. 16

Project Description:
Pursuant to the Federal Clean Water Act, 33 U.S.C. § 1342, all point source discharges to navigable waters from industrial facilities must obtain permits under the NPDES Program. The FDEP administers the NPDES program in Florida. DEF's Anclote, Bartow, and Crystal River North, Crystal River South, and Suwannee NPDES permits were issued on 11/25/2015, 1/5/2016, 7/18/11, 4/7/2014, and 10/6/2016, respectively. Crystal River North NPDES permit is in the renewal process. All facilities are required to meet new permitting conditions. In Docket No. 20110007-EI, the Commission approved recovery of costs associated with new requirements included or expected to be included in the new renewal permits, including: thermal studies, aquatic organism return studies and implementation, whole effluent toxicity testing, dissolved oxygen (DO) studies (Bartow only), and freeboard limitation related studies (Bartow only). As noted in DEF's 2/8/12 program update, on 12/14/11, the FDEP issued a final NPDES renewal permit and associated Administrative Order (AO) for the Suwannee Plant. The AO includes a new requirement to assess copper discharges that DEF did not anticipate when it filed its petition in 2011.

Project Accomplishments:
DEF continues to perform whole effluent toxicity testing, implementing initial 316(b) rule requirements based on NPDES permit schedules at affected facilities which includes literature review and analysis, additional field study, and reporting requirements in accordance to NPDES permit requirements. Bartow freeboard limitation study was completed in May 2011 and submitted to FDEP on 6/23/11. The FDEP approved DEF's corrective action plan and Bartow is in compliance with Administrative Order as of December 2014. The copper discharge study at the Suwannee plant has been completed and a final report was submitted to the FDEP in June 2014 resulting in a corrective action of retiring the steam units. The Suwannee plant retired Units 1, 2 and 3 in December 2016.

Project Fiscal Expenditures:
2020 O&M expenditures are estimated to be $30k. No capital expenditures are forecasted for 2020.

Project Progress Summary:
DEF has begun complying with the requirements of the NPDES permits. Aquatic organism return study requirements have been postponed to align with the final EPA 316(b) rule requirements (Bartow/Anclote Plants) which was published 8/15/14. The aquatic organism return requirement is not a requirement in the Crystal River North NPDES permit. The dissolved oxygen study of cooling water intake and discharge at the Bartow plant was completed and the results of the study demonstrated there is no negative impact on DO due to the plant's operation. The final DO report was submitted to the FDEP on November 20, 2012, and the Department has not required any additional action. The Suwannee Steam station was retired and removed from service; therefore, WET testing is no longer required.

Project Projections:
2021 estimated O&M expenditures are $32k. No capital expenditures are expected in 2021.

Project Title: **Mercury & Air Toxic Standards (MATS) CR4 & CR5**
Project No. 17

Project Description:
The Commission approved ECRC recovery of DEF's costs for compliance with new hazardous air pollutant standards at Crystal River Units 4 & 5 (CR4&5) in Order No. PSC-2011-0553-FOF-EI. The final MATS rule was issued by the EPA on 12/21/11. The FDEP granted a limited, one-year extension for the mercury-related requirements on 3/12/15. DEF will utilize the co-benefits of existing FGD and SCR systems as the primary MATS emission controls. CR4&5 have demonstrated compliance with all MATS requirements as of 4/16/16.

Project Accomplishments:
DEF installed oxidation-reduction potential (ORP) probes and mercury re-emission control systems for MATS emissions control. In addition, continuous emissions monitoring systems (CEMS) were installed for compliance demonstration with particulate matter (PM) and mercury emissions. Appendix K sorbent traps have been certified and maintained to serve as backup monitors for mercury CEMS.

Project Fiscal Expenditures:
2020 O&M expenditures are estimated to be $360K.

Project Progress Summary:
Initial implementation of the CR4&5 MATS compliance plan is complete.

Project Projections:
2021 estimated O&M is $120k. No capital expenditures are forecasted.

Project Title: **Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion**
Project No. 17.1

Project Description:
Convert existing Anclote Units to use 100% natural gas to be in compliance with MATS as approved by the Commission in Order No. PSC-2012-0432-PAA-EI.

Project Accomplishments:
Unit 1 and Unit 2 gas conversions were completed 7/13/13 and 12/2/13, respectively. Unit 1 and Unit 2 Forced Draft (FD) fan modification work was completed 5/22/14 and 11/17/14, respectively.

Project Fiscal Expenditures:
No 2020 expenditures are expected for this project.

Project Progress Summary:
This project is in-service.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Mercury & Air Toxic Standards (MATS) CR1 & CR2**
Project No. 17.2

Project Description:
DEF implemented its CR1&2 MATS Compliance Plan as approved by the Commission in Order No. PSC-2014-0173-PAA-EI. CR1&2 have demonstrated compliance with all MATS requirements as of 4/16/2016.

Project Accomplishments:
DEF finalized its CR1&2 MATS Compliance Plan in December 2013 and began implementation in early 2014. Modifications were made to the electrostatic precipitators (ESPs) to improve particulate collection efficiency, and reagent injection systems were installed to reduce hydrogen chloride (HCl) and mercury emissions. Appendix K sorbent traps were installed for compliance demonstration with mercury emissions.

Project Fiscal Expenditures:
2020 O&M expenditures are expected to be $0k.

Project Progress Summary:
CR1&2 have been retired.

Project Projections:
DEF does not expect to incur any capital expenditures or O&M costs in 2021.

Project Title: **Coal Combustion Residual (CCR) Rule**
Project No. 18

Project Description:
The Coal Combustion Residual (CCR) Rule was published in the Federal Register on 4/17/15 and is effective 10/19/15. This rule regulates the disposal of CCR as non-hazardous solid waste, and contains new requirements for CCR landfills and CCR surface impoundments. It also specifies implementation guidelines for compliance. The CCR compliance deadlines vary, with compliance obligations required as early as 10/19/15. The rule is self-implementing, meaning that affected facilities must comply with the new regulations irrespective of whether the rule is adopted by the State of Florida. The rule has specific impacts on the ash landfill, Flue Gas Desulfurization (FGD) lined blowdown ponds and temporary gypsum pad at the Crystal River site. No other DEF operating facilities are impacted by the CCR rule.

Project Accomplishments:
Annual inspections were completed for the FGD Blowdown Ponds and Ash Landfill. Maintenance, vegetation management, and weekly inspections for the FGD Blowdown Ponds and Ash Landfill continue. The groundwater assessment project for the FGD Blowdown Ponds and Ash Landfill continued per the requirements of the rule.

Project Fiscal Expenditures:
2020 estimated O&M expenditures are $917k. Capital forecast is $1.3M.

Project Progress Summary:
Ash Landfill: currently O&M work to remove some accumulated CCR material in the perimeter ditch, also some capital work after that for a new lined basin / ditch area, which will help avoid further accumulation in the future.

FGD Blowdown Ponds: Dewatering and solids removal from the primary and backup FGD Blowdown Ponds were completed. Development of a closure plan for the FGD Blowdown pond is underway. Pond closure was substantially completed during 2019, and alternative source demonstration was completed to address statistically significant increases in certain constituents in groundwater.

Vegetation Management & Inspection Work: More frequent mowing and inspection work is being performed, to comply with the CCR Rule.

Project Projections:
2021 estimated O&M expenditures are $278k, capital is forecasted to be $250k.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % by Rate Class
January 2021 - December 2021

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrsx(1))	(4) NCP Class Max Load Factor	(5) Delivery Efficiency Factor	(6) Sales at Source (Generation) (mWh) (2)/(5)	(7) Avg 12 CP at Source (MW) (3)/(5)	7(a) Sales at Source (Distrib Svc Only) (mWh)	(8) Class Max MW at Source Level (Distrib Svc) (7a)/(8760hrs/(4))	(9) mWh Sales at Source Energy Allocator (%)	(10) 12CP Demand Transmission Allocator (%)	(11) NCP Distribution Allocator (%)	(12) 12CP & 1/13 AD Demand Allocator (%)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	0.548	21,141,521	4,405.75	0.370	0.9307248	22,715,115	4,733.68	22,715,115	7,007.8	53.677%	61.440%	66.399%	60.843%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.576	2,057,599	408.02	0.451	0.9307248	2,210,749	438.39	2,210,749	559.4	5.224%	5.690%	5.300%	5.654%
Primary	0.576	14,043	2.78	0.451	0.9736607	14,423	2.86	14,423	3.6	0.034%	0.037%	0.035%	0.037%
Transmission	0.576	2,593	0.51	0.451	0.9836607	2,636	0.52	0	0.0	0.006%	0.007%	0.000%	0.007%
										5.264%	5.734%	5.335%	5.698%
General Service													
GS-2 Secondary	1.000	194,563	22.21	1.000	0.9307248	209,044	23.86	209,044	23.9	0.494%	0.310%	0.226%	0.324%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.742	10,950,999	1,683.92	0.626	0.9307248	11,766,098	1,809.26	11,766,098	2,145.7	27.804%	23.483%	20.331%	23.815%
Primary	0.742	2,001,891	307.83	0.626	0.9736607	2,056,046	316.16	2,056,046	374.9	4.859%	4.104%	3.553%	4.162%
Secondary Del/ Primary Mtr	0.742	28,262	4.35	0.626	0.9736607	29,027	4.46	29,027	5.3	0.069%	0.058%	0.050%	0.059%
Transm Del/ Primary Mtr	0.742	0	0.00	0.626	0.9736607	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transmission	0.742	103,104	15.85	0.626	0.9836607	104,817	16.12	0	0.0	0.248%	0.209%	0.000%	0.212%
SS-1 Primary	0.796	36,645	5.26	0.324	0.9736607	37,636	5.40	37,636	13.3	0.089%	0.070%	0.126%	0.072%
Transm Del/ Transm Mtr	0.796	5,412	0.78	0.324	0.9836607	5,502	0.79	0	0.0	0.013%	0.010%	0.000%	0.010%
Transm Del/ Primary Mtr	0.796	1,821	0.26	0.324	0.9736607	1,870	0.27	0	0.0	0.004%	0.003%	0.000%	0.004%
										33.085%	27.938%	24.059%	28.334%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	1.082	0	0.00	0.334	0.9307248	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	1.082	61,840	6.52	0.334	0.9736607	63,513	6.70	63,513	21.7	0.150%	0.087%	0.206%	0.092%
SS-3 Primary	1.248	68,295	6.25	0.380	0.9736607	70,142	6.42	70,142	21.1	0.166%	0.083%	0.200%	0.090%
										0.316%	0.170%	0.405%	0.181%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.911	445,099	55.76	0.707	0.9307248	478,228	59.91	478,228	77.2	1.130%	0.778%	0.732%	0.805%
Sec Del/Primary Mtr	0.911	5,866	0.73	0.707	0.9736607	6,025	0.75	6,025	1.0	0.014%	0.010%	0.009%	0.010%
Primary Del / Primary Mtr	0.911	1,226,102	153.60	0.707	0.9736607	1,259,270	157.75	1,259,270	203.4	2.976%	2.048%	1.927%	2.119%
Primary Del / Transm Mtr	0.911	301	0.04	0.707	0.9836607	306	0.04	306	0.0	0.001%	0.000%	0.000%	0.001%
Transm Del/ Transm Mtr	0.911	459,412	57.55	0.707	0.9836607	467,043	58.51	0	0.0	1.104%	0.759%	0.000%	0.786%
Transm Del/ Primary Mtr	0.911	369,971	46.35	0.707	0.9736607	379,979	47.60	0	0.0	0.898%	0.618%	0.000%	0.639%
SS-2 Primary	0.686	14,726	2.45	0.272	0.9736607	15,124	2.52	15,124	6.3	0.036%	0.033%	0.060%	0.033%
Transm Del/ Transm Mtr	0.686	3,450	0.57	0.272	0.9836607	3,507	0.58	0	0.0	0.008%	0.008%	0.000%	0.008%
Transm Del/ Primary Mtr	0.686	45,318	7.54	0.272	0.9736607	46,544	7.75	0	0.0	0.110%	0.101%	0.000%	0.101%
										6.276%	4.353%	2.728%	4.501%
Lighting													
LS-1 (Secondary)	10.191	349,344	3.91	0.479	0.9307248	375,347	4.20	375,347	89.5	0.887%	0.055%	0.848%	0.119%
		39,588,176	7,198.81			42,317,991	7,704.50	41,306,092	10,554.1	100.000%	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2018
(2) Projected kWh sales for the period January 2020 to December 2020
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2018
(5) Based on system average line loss analysis for 2018
(6) Column 2 / Column 5
(7) Column 3 / Column 5
(7a) Column 6 excluding transmission service
(8) Calculated: Column 7a / (8,760 hours/ Column 4)
(9) Column 6/ Total Column 6
(10) Column 7/ Total Column 7
(11) Column 8/ Total Column 8
(12) Column 9 x 1/13 + Column 10 x 12/13

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class
January 2021 - December 2021

Rate Class	(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Demand Allocator (%)	(3) NCP Distribution Allocator (%)	(4) 12CP & 1/13th AD Demand Allocator (%)	(5) Energy-Related Costs ($)	(6) Transmission Demand Costs ($)	(7) Distribution Demand Costs ($)	(8) Production Demand Costs ($)	(9) Total Environmental Costs ($)	(10) Projected Effective Sales at Meter Level (mWh)	**(11) Environmental Cost Recovery Factors (cents/kWh)**
Residential											
RS-1, RST-1, RSL-1, RSL-2, RSS-1											
Secondary	53.677%	61.440%	66.399%	60.843%	$18,995,736	($59,349)	($101,417)	$2,012,982	$20,847,952	21,141,521	**0.099**
General Service Non-Demand											
GS-1, GST-1											
Secondary										2,057,599	**0.098**
Primary										13,903	**0.097**
Transmission										2,541	**0.096**
TOTAL GS	5.264%	5.734%	5.335%	5.698%	$1,863,026	($5,539)	($8,148)	$188,512	$2,037,851	**2,074,042**	
General Service											
GS-2 Secondary	0.494%	0.310%	0.226%	0.324%	$174,815	($299)	($345.35)	$10,716.40	$184,887	194,563	**0.095**
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										10,950,999	**0.096**
Primary										2,047,933	**0.095**
Transmission										106,346	**0.094**
TOTAL GSD	33.085%	27.938%	24.059%	28.334%	$11,708,469	($26,986)	($36,748)	$937,406	$12,582,141	**13,105,277**	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	**0.091**
Primary										128,834	**0.090**
Transmission										-	**0.089**
TOTAL CS	0.316%	0.170%	0.405%	0.181%	$111,771	($164)	($619)	$6,003	$116,990	**128,834**	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										445,099	**0.093**
Primary										1,645,363	**0.092**
Transmission										453,900	**0.091**
TOTAL IS	6.276%	4.353%	2.728%	4.501%	$2,221,129	($4,205)	($4,167)	$148,927	$2,361,683	**2,544,362**	
Lighting											
LS-1 Secondary	0.887%	0.055%	0.848%	0.119%	$313,887	($53)	($1,294.56)	$3,923.91	$316,464	349,344	**0.091**
	100.000%	100.000%	100.000%	100.000%	$35,388,833	($96,595)	($152,739)	$3,308,471	$38,447,970	39,537,943	**0.097**

Notes:

(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 10
(3) From Form 42-6P, Column 11
(4) From Form 42-6P, Column 12
(5) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(6) Column 2 x Total Transmission Demand Jurisdictional Dollars from Form 42-1P, line 5
(7) Column 3 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8) Column 4 x Total Production Demand Jurisdictional Dollars from Form 42-1P, line 5
(9) Column 5 + Column 6 + Column 7 + Column 8
(10) Projected kWh sales at secondary voltage level for the period January 2021 to December 2021
(11) (Column 9 / Column 10)/10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projected Period Amount
January 2021 - December 2021

Capital Structure and Cost Rates

Class of Capital	Retail	Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$	6,641,460,173	43.82%	0.10500	4.60%	6.10%
PS		-	0.00%	0.00000	0.00%	0.00%
LTD		5,949,952,701	39.26%	0.04371	1.72%	1.72%
STD		(71,619,953)	-0.47%	0.01803	-0.01%	-0.01%
CD-Active		189,294,628	1.25%	0.02366	0.03%	0.03%
CD-Inactive		1,593,395	0.01%	0.00000	0.00%	0.00%
ADIT		2,265,753,808	14.95%	0.00000	0.00%	0.00%
FAS 109		-	0.00%	0.00000	0.00%	0.00%
ITC		180,081,511	1.19%	0.07604	0.09%	0.09%
Total	$	15,156,516,263	100.00%		6.43%	7.92%
				Total Debt	1.83%	1.83%
				Total Equity	4.60%	6.10%

Note> 2021 WACC that complies with the Amended Unopposed Joint Motion to Modify Order No. PSC-2012-0425-PAA-UE Regarding Weighted Average Cost of Capital Methodology approved May 20, 2020 in Docket No, 20200118-EU, Order No. PSC-2020-0165-PAA-EU.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Capital Program Detail

January 2021 - December 2021
Calculation of Projected Period Amount

Docket No. 20200007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 26
PARTY: CAM-6
DESCRIPTION: Capital Program
DetailJanuary 2021 – December 2021

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	
3	Less: Accumulated Depreciation			(513,603)	(517,288)	(520,973)	(524,658)	(528,343)	(532,028)	(535,713)	(539,398)	(543,083)	(546,768)	(550,453)	(554,138)	(557,823)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$960,198	$956,513	$952,828	$949,143	$945,458	$941,773	$938,088	$934,403	$930,718	$927,033	$923,348	$919,663	$915,978	
6	Average Net Investment				958,356	954,671	950,986	947,301	943,616	939,931	936,246	932,561	928,876	925,191	921,506	917,821	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		1,459	1,454	1,448	1,442	1,437	1,431	1,426	1,420	1,414	1,409	1,403	1,397	17,140
	b. Equity Component Grossed Up For Taxes		6.10%		4,868	4,850	4,831	4,812	4,793	4,775	4,756	4,737	4,719	4,700	4,681	4,662	57,184
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.0000%			3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008150			1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	12,012
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$11,013	$10,990	$10,965	$10,940	$10,916	$10,892	$10,868	$10,843	$10,819	$10,795	$10,770	$10,745	$130,556
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$11,013	$10,990	$10,965	$10,940	$10,916	$10,892	$10,868	$10,843	$10,819	$10,795	$10,770	$10,745	$130,556

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation			(1,382,471)	(1,391,610)	(1,400,749)	(1,409,888)	(1,419,027)	(1,428,166)	(1,437,305)	(1,446,444)	(1,455,583)	(1,464,722)	(1,473,861)	(1,483,000)	(1,492,139)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$279,193	$270,054	$260,915	$251,776	$242,637	$233,498	$224,359	$215,220	$206,081	$196,942	$187,803	$178,664	$169,525	
6	Average Net Investment				274,624	265,485	256,346	247,207	238,068	228,929	219,790	210,651	201,512	192,373	183,234	174,095	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		418	404	390	376	362	349	335	321	307	293	279	265	4,099
	b. Equity Component Grossed Up For Taxes		6.10%		1,395	1,349	1,302	1,256	1,209	1,163	1,116	1,070	1,024	977	931	884	13,676
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	6.6000%			9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007220			1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$11,952	$11,892	$11,831	$11,771	$11,710	$11,651	$11,590	$11,530	$11,470	$11,409	$11,349	$11,288	$139,443
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$11,952	$11,892	$11,831	$11,771	$11,710	$11,651	$11,590	$11,530	$11,470	$11,409	$11,349	$11,288	$139,443

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (B)			49,060	43,609	38,158	32,707	27,256	21,804	16,353	10,902	5,451	0	0	0	0	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$49,060	$43,609	$38,158	$32,707	$27,256	$21,804	$16,353	$10,902	$5,451	$0	$0	$0	$0	
6	Average Net Investment				46,334	40,883	35,432	29,981	24,530	19,079	13,628	8,177	2,726	0	0	0	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		71	62	54	46	37	29	21	12	4	0	0	0	336
	b. Equity Component Grossed Up For Taxes		6.10%		235	208	180	152	125	97	69	42	14	0	0	0	1,122
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	4.8000%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (B)				5,451	5,451	5,451	5,451	5,451	5,451	5,451	5,451	5,451	0	0	0	49,060
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008000			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$5,757	$5,721	$5,685	$5,649	$5,613	$5,577	$5,541	$5,505	$5,469	$0	$0	$0	$50,518
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$5,757	$5,721	$5,685	$5,649	$5,613	$5,577	$5,541	$5,505	$5,469	$0	$0	$0	$50,518

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3	Less: Accumulated Depreciation			(286,213)	(288,035)	(289,857)	(291,679)	(293,501)	(295,323)	(297,145)	(298,967)	(300,789)	(302,611)	(304,433)	(306,255)	(308,077)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$444,082	$442,260	$440,438	$438,616	$436,794	$434,972	$433,150	$431,328	$429,506	$427,684	$425,862	$424,040	$422,218	
6	Average Net Investment				443,171	441,349	439,527	437,705	435,883	434,061	432,239	430,417	428,595	426,773	424,951	423,129	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		675	672	669	666	664	661	658	655	653	650	647	644	7,914
	b. Equity Component Grossed Up For Taxes		6.10%		2,251	2,242	2,233	2,223	2,214	2,205	2,196	2,186	2,177	2,168	2,159	2,149	26,403
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.9936%			1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	1,822	21,864
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.011030			671	671	671	671	671	671	671	671	671	671	671	671	8,052
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$5,419	$5,407	$5,395	$5,382	$5,371	$5,359	$5,347	$5,334	$5,323	$5,311	$5,299	$5,286	$64,233
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$5,419	$5,407	$5,395	$5,382	$5,371	$5,359	$5,347	$5,334	$5,323	$5,311	$5,299	$5,286	$64,233

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.
(B) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation			(460,824)	(463,676)	(466,528)	(469,380)	(472,232)	(475,084)	(477,936)	(480,788)	(483,640)	(486,492)	(489,344)	(492,196)	(495,048)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$576,375	$573,523	$570,671	$567,819	$564,967	$562,115	$559,263	$556,411	$553,559	$550,707	$547,855	$545,003	$542,151	
6	Average Net Investment				574,949	572,097	569,245	566,393	563,541	560,689	557,837	554,985	552,133	549,281	546,429	543,577	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		875	871	867	862	858	854	849	845	841	836	832	828	10,218
	b. Equity Component Grossed Up For Taxes		6.10%		2,921	2,906	2,892	2,877	2,863	2,848	2,834	2,819	2,805	2,790	2,776	2,761	34,092
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.3000%			2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008390			725	725	725	725	725	725	725	725	725	725	725	725	8,700
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$7,373	$7,354	$7,336	$7,316	$7,298	$7,279	$7,260	$7,241	$7,223	$7,203	$7,185	$7,166	$87,234
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$7,373	$7,354	$7,336	$7,316	$7,298	$7,279	$7,260	$7,241	$7,223	$7,203	$7,185	$7,166	$87,234

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	3,616,904	
3	Less: Accumulated Depreciation			(1,010,138)	(1,017,975)	(1,025,812)	(1,033,649)	(1,041,486)	(1,049,323)	(1,057,160)	(1,064,997)	(1,072,834)	(1,080,671)	(1,088,508)	(1,096,345)	(1,104,182)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,606,766	$2,598,929	$2,591,092	$2,583,255	$2,575,418	$2,567,581	$2,559,744	$2,551,907	$2,544,070	$2,536,233	$2,528,396	$2,520,559	$2,512,722	
6	Average Net Investment				2,602,847	2,595,010	2,587,173	2,579,336	2,571,499	2,563,662	2,555,825	2,547,988	2,540,151	2,532,314	2,524,477	2,516,640	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		3,963	3,951	3,939	3,927	3,915	3,903	3,891	3,880	3,868	3,856	3,844	3,832	46,769
	b. Equity Component Grossed Up For Taxes		6.10%		13,222	13,182	13,142	13,103	13,063	13,023	12,983	12,943	12,904	12,864	12,824	12,784	156,037
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.6000%			7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	7,837	94,044
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008220			2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	2,478	29,736
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$27,500	$27,448	$27,396	$27,345	$27,293	$27,241	$27,189	$27,138	$27,087	$27,035	$26,983	$26,931	$326,586
	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				$27,500	$27,448	$27,396	$27,345	$27,293	$27,241	$27,189	$27,138	$27,087	$27,035	$26,983	$26,931	$326,586

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation			(69,018)	(69,259)	(69,500)	(69,741)	(69,982)	(70,223)	(70,464)	(70,705)	(70,946)	(71,187)	(71,428)	(71,669)	(71,910)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$72,417	$72,176	$71,935	$71,694	$71,453	$71,212	$70,971	$70,730	$70,489	$70,248	$70,007	$69,766	$69,525	
6	Average Net Investment				72,296	72,055	71,814	71,573	71,332	71,091	70,850	70,609	70,368	70,127	69,886	69,645	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		110	110	109	109	109	108	108	108	107	107	106	106	1,297
	b. Equity Component Grossed Up For Taxes		6.10%		367	366	365	364	362	361	360	359	357	356	355	354	4,326
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.0482%			241	241	241	241	241	241	241	241	241	241	241	241	2,892
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009910			117	117	117	117	117	117	117	117	117	117	117	117	1,404
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$835	$834	$832	$831	$829	$827	$826	$825	$822	$821	$819	$818	$9,919
	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				$835	$834	$832	$831	$829	$827	$826	$825	$822	$821	$819	$818	$9,919

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	2,365,947	
3	Less: Accumulated Depreciation			(59,908)	(62,838)	(65,768)	(68,698)	(71,628)	(74,558)	(77,488)	(80,418)	(83,348)	(86,278)	(89,208)	(92,138)	(95,068)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,306,039	$2,303,109	$2,300,179	$2,297,249	$2,294,319	$2,291,389	$2,288,459	$2,285,529	$2,282,599	$2,279,669	$2,276,739	$2,273,809	$2,270,879	
6	Average Net Investment				2,304,574	2,301,644	2,298,714	2,295,784	2,292,854	2,289,924	2,286,994	2,284,064	2,281,134	2,278,204	2,275,274	2,272,344	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		3,509	3,504	3,500	3,496	3,491	3,487	3,482	3,478	3,473	3,469	3,464	3,460	41,813
	b. Equity Component Grossed Up For Taxes		6.10%		11,707	11,692	11,677	11,662	11,647	11,632	11,618	11,603	11,588	11,573	11,558	11,543	139,500
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.4860%			2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930	35,160
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.001645			324	324	324	324	324	324	324	324	324	324	324	324	3,888
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$18,470	$18,450	$18,431	$18,412	$18,392	$18,373	$18,354	$18,335	$18,315	$18,296	$18,276	$18,257	$220,361
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$18,470	$18,450	$18,431	$18,412	$18,392	$18,373	$18,354	$18,335	$18,315	$18,296	$18,276	$18,257	$220,361

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation			($91,686)	(92,211)	(92,736)	(93,261)	(93,786)	(94,311)	(94,836)	(95,361)	(95,886)	(96,411)	(96,936)	(97,461)	(97,986)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$198,611	$198,086	$197,561	$197,036	$196,511	$195,986	$195,461	$194,936	$194,411	$193,886	$193,361	$192,836	$192,311	
6	Average Net Investment				198,349	197,824	197,299	196,774	196,249	195,724	195,199	194,674	194,149	193,624	193,099	192,574	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		302	301	300	300	299	298	297	296	296	295	294	293	3,571
	b. Equity Component Grossed Up For Taxes		6.10%		1,008	1,005	1,002	1,000	997	994	992	989	986	984	981	978	11,916
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.1722%			525	525	525	525	525	525	525	525	525	525	525	525	6,300
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.006390			155	155	155	155	155	155	155	155	155	155	155	155	1,860
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,990	$1,986	$1,982	$1,980	$1,976	$1,972	$1,969	$1,965	$1,962	$1,959	$1,955	$1,951	$23,647
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,990	$1,986	$1,982	$1,980	$1,976	$1,972	$1,969	$1,965	$1,962	$1,959	$1,955	$1,951	$23,647

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements (B)			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (B)		78,814	70,057	61,300	52,543	43,785	35,028	26,271	17,514	8,757	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$78,814	$70,057	$61,300	$52,543	$43,785	$35,028	$26,271	$17,514	$8,757	$0	$0	$0	$0	
6	Average Net Investment			74,435	65,678	56,921	48,164	39,407	30,650	21,893	13,136	4,379	0	0	0	
7	Return on Average Net Investment (A)															
	a. Debt Component	1.83%		113	100	87	73	60	47	33	20	7	0	0	0	540
	b. Equity Component Grossed Up For Taxes	6.10%		378	334	289	245	200	156	111	67	22	0	0	0	1,802
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.0000%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization (B)			8,757	8,757	8,757	8,757	8,757	8,757	8,757	8,757	8,757	0	0	0	78,814
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008000		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)			$9,248	$9,191	$9,133	$9,075	$9,017	$8,960	$8,901	$8,844	$8,786	$0	$0	$0	$81,156
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$9,248	$9,191	$9,133	$9,075	$9,017	$8,960	$8,901	$8,844	$8,786	$0	$0	$0	$81,156

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3	Less: Accumulated Depreciation		(66,745)	(67,103)	(67,461)	(67,819)	(68,177)	(68,535)	(68,893)	(69,251)	(69,609)	(69,967)	(70,325)	(70,683)	(71,041)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$208,602	$208,244	$207,886	$207,528	$207,170	$206,812	$206,454	$206,096	$205,738	$205,380	$205,022	$204,664	$204,306	
6	Average Net Investment			208,423	208,065	207,707	207,349	206,991	206,633	206,275	205,917	205,559	205,201	204,843	204,485	
7	Return on Average Net Investment (A)															
	a. Debt Component	1.83%		317	317	316	316	315	315	314	314	313	312	312	311	3,772
	b. Equity Component Grossed Up For Taxes	6.10%		1,059	1,057	1,055	1,053	1,051	1,050	1,048	1,046	1,044	1,042	1,041	1,039	12,585
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.5610%		358	358	358	358	358	358	358	358	358	358	358	358	4,296
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008150		187	187	187	187	187	187	187	187	187	187	187	187	2,244
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$1,921	$1,919	$1,916	$1,914	$1,911	$1,910	$1,907	$1,905	$1,902	$1,899	$1,898	$1,895	$22,897
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$1,921	$1,919	$1,916	$1,914	$1,911	$1,910	$1,907	$1,905	$1,902	$1,899	$1,898	$1,895	$22,897

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.
(B) Investment amortized over one year as approved in Order No. PSC-2019-0500-FOF-EI.

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation			(61,695)	(62,079)	(62,463)	(62,847)	(63,231)	(63,615)	(63,999)	(64,383)	(64,767)	(65,151)	(65,535)	(65,919)	(66,303)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$137,293	$136,909	$136,525	$136,141	$135,757	$135,373	$134,989	$134,605	$134,221	$133,837	$133,453	$133,069	$132,685	
6	Average Net Investment				137,101	136,717	136,333	135,949	135,565	135,181	134,797	134,413	134,029	133,645	133,261	132,877	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		209	208	208	207	206	206	205	205	204	203	203	202	2,466
	b. Equity Component Grossed Up For Taxes		6.10%		696	695	693	691	689	687	685	683	681	679	677	675	8,231
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.3149%			384	384	384	384	384	384	384	384	384	384	384	384	4,608
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.011030			183	183	183	183	183	183	183	183	183	183	183	183	2,196
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$1,472	$1,470	$1,468	$1,465	$1,462	$1,460	$1,457	$1,455	$1,452	$1,449	$1,447	$1,444	$17,501
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$1,472	$1,470	$1,468	$1,465	$1,462	$1,460	$1,457	$1,455	$1,452	$1,449	$1,447	$1,444	$17,501

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation			(35,283)	(35,502)	(35,721)	(35,940)	(36,159)	(36,378)	(36,597)	(36,816)	(37,035)	(37,254)	(37,473)	(37,692)	(37,911)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$52,384	$52,165	$51,946	$51,727	$51,508	$51,289	$51,070	$50,851	$50,632	$50,413	$50,194	$49,975	$49,756	
6	Average Net Investment				52,275	52,056	51,837	51,618	51,399	51,180	50,961	50,742	50,523	50,304	50,085	49,866	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		80	79	79	79	78	78	78	77	77	77	76	76	934
	b. Equity Component Grossed Up For Taxes		6.10%		266	264	263	262	261	260	259	258	257	256	254	253	3,113
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	3.0000%			219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008220			60	60	60	60	60	60	60	60	60	60	60	60	720
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$625	$622	$621	$620	$618	$617	$616	$614	$613	$612	$609	$608	$7,395
	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				$625	$622	$621	$620	$618	$617	$616	$614	$613	$612	$609	$608	$7,395

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation			($123,343)	(124,130)	(124,917)	(125,704)	(126,491)	(127,278)	(128,065)	(128,852)	(129,639)	(130,426)	(131,213)	(132,000)	(132,787)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$226,241	$225,454	$224,667	$223,880	$223,093	$222,306	$221,519	$220,732	$219,945	$219,158	$218,371	$217,584	$216,797	
6	Average Net Investment				225,847	225,060	224,273	223,486	222,699	221,912	221,125	220,338	219,551	218,764	217,977	217,190	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		344	343	341	340	339	338	337	335	334	333	332	331	4,047
	b. Equity Component Grossed Up For Taxes		6.10%		1,147	1,143	1,139	1,135	1,131	1,127	1,123	1,119	1,115	1,111	1,107	1,103	13,500
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.7000%			787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007220			210	210	210	210	210	210	210	210	210	210	210	210	2,520
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,488	$2,483	$2,477	$2,472	$2,467	$2,462	$2,457	$2,451	$2,446	$2,441	$2,436	$2,431	$29,511
	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				$2,488	$2,483	$2,477	$2,472	$2,467	$2,462	$2,457	$2,451	$2,446	$2,441	$2,436	$2,431	$29,511

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation			(71,418)	(71,841)	(72,264)	(72,687)	(73,110)	(73,533)	(73,956)	(74,379)	(74,802)	(75,225)	(75,648)	(76,071)	(76,494)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$310,142	$309,719	$309,296	$308,873	$308,450	$308,027	$307,604	$307,181	$306,758	$306,335	$305,912	$305,489	$305,066	
6	Average Net Investment				309,930	309,507	309,084	308,661	308,238	307,815	307,392	306,969	306,546	306,123	305,700	305,277	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		472	471	471	470	469	469	468	467	467	466	465	465	5,620
	b. Equity Component Grossed Up For Taxes		6.10%		1,574	1,572	1,570	1,568	1,566	1,564	1,562	1,559	1,557	1,555	1,553	1,551	18,751
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.3299%			423	423	423	423	423	423	423	423	423	423	423	423	5,076
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008390			267	267	267	267	267	267	267	267	267	267	267	267	3,204
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,736	$2,733	$2,731	$2,728	$2,725	$2,723	$2,720	$2,716	$2,714	$2,711	$2,708	$2,706	$32,651
	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				$2,736	$2,733	$2,731	$2,728	$2,725	$2,723	$2,720	$2,716	$2,714	$2,711	$2,708	$2,706	$32,651

(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	2,149,100	
3	Less: Accumulated Depreciation		(288,305)	(292,729)	(297,153)	(301,577)	(306,001)	(310,425)	(314,849)	(319,273)	(323,697)	(328,121)	(332,545)	(336,969)	(341,393)	
4	CWIP - Non-Interest Bearing (B)		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,860,795	$1,856,371	$1,851,947	$1,847,523	$1,843,099	$1,838,675	$1,834,251	$1,829,827	$1,825,403	$1,820,979	$1,816,555	$1,812,131	$1,807,707	
6	Average Net Investment			1,858,583	1,854,159	1,849,735	1,845,311	1,840,887	1,836,463	1,832,039	1,827,615	1,823,191	1,818,767	1,814,343	1,809,919	
7	Return on Average Net Investment (A)															
	a. Debt Component	1.83%		2,830	2,823	2,816	2,810	2,803	2,796	2,789	2,783	2,776	2,769	2,762	2,756	33,513
	b. Equity Component Grossed Up For Taxes	6.10%		9,441	9,419	9,396	9,374	9,351	9,329	9,306	9,284	9,262	9,239	9,217	9,194	111,812
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.4700%		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.000525		94	94	94	94	94	94	94	94	94	94	94	94	1,128
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$16,789	$16,760	$16,730	$16,702	$16,672	$16,643	$16,613	$16,585	$16,556	$16,526	$16,497	$16,468	$199,541
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$16,789	$16,760	$16,730	$16,702	$16,672	$16,643	$16,613	$16,585	$16,556	$16,526	$16,497	$16,468	$199,541

For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	83,383,699	
3	Less: Accumulated Depreciation		(2,405,761)	(2,509,018)	(2,612,275)	(2,715,532)	(2,818,789)	(2,922,046)	(3,025,303)	(3,128,560)	(3,231,817)	(3,335,074)	(3,438,331)	(3,541,588)	(3,644,845)	
4	CWIP - Non-Interest Bearing (B)		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$80,977,938	$80,874,681	$80,771,424	$80,668,167	$80,564,910	$80,461,653	$80,358,396	$80,255,139	$80,151,882	$80,048,625	$79,945,368	$79,842,111	$79,738,854	
6	Average Net Investment			80,926,309	80,823,052	80,719,795	80,616,538	80,513,281	80,410,024	80,306,767	80,203,510	80,100,253	79,996,996	79,893,739	79,790,482	
7	Return on Average Net Investment (A)															
	a. Debt Component	1.83%		123,217	123,060	122,903	122,745	122,588	122,431	122,274	122,117	121,959	121,802	121,645	121,488	1,468,229
	b. Equity Component Grossed Up For Taxes	6.10%		411,093	410,569	410,044	409,520	408,995	408,471	407,946	407,422	406,897	406,372	405,848	405,323	4,898,500
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.4860%		103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	103,257	1,239,084
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.000525		3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	43,764
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$641,214	$640,533	$639,851	$639,169	$638,487	$637,806	$637,124	$636,443	$635,760	$635,078	$634,397	$633,715	$7,649,577
	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			$641,214	$640,533	$639,851	$639,169	$638,487	$637,806	$637,124	$636,443	$635,760	$635,078	$634,397	$633,715	$7,649,577

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4r) - CR4 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	660,998	
3	Less: Accumulated Depreciation			(120,529)	(121,890)	(123,251)	(124,612)	(125,973)	(127,334)	(128,695)	(130,056)	(131,417)	(132,778)	(134,139)	(135,500)	(136,861)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$540,469	$539,108	$537,747	$536,386	$535,025	$533,664	$532,303	$530,942	$529,581	$528,220	$526,859	$525,498	$524,137	
6	Average Net Investment				539,789	538,428	537,067	535,706	534,345	532,984	531,623	530,262	528,901	527,540	526,179	524,818	
7	Return on Average Net Investment (A)																
	a. Debt Component		1.83%		822	820	818	816	814	812	809	807	805	803	801	799	9,726
	b. Equity Component Grossed Up For Taxes		6.10%		2,742	2,735	2,728	2,721	2,714	2,707	2,701	2,694	2,687	2,680	2,673	2,666	32,448
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.4700%			1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	16,332
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.000525			29	29	29	29	29	29	29	29	29	29	29	29	348
	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	$4,945	$4,936	$4,927	$4,918	$4,909	$4,900	$4,891	$4,882	$4,873	$4,864	$4,855	$58,854
	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				$4,954	$4,945	$4,936	$4,927	$4,918	$4,909	$4,900	$4,891	$4,882	$4,873	$4,864	$4,855	$58,854

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4s) - CR5 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements				0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other				0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base			$505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	505,904	
3	Less: Accumulated Depreciation			(79,315)	(80,356)	(81,397)	(82,438)	(83,479)	(84,520)	(85,561)	(86,602)	(87,643)	(88,684)	(89,725)	(90,766)	(91,807)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$426,589	$425,548	$424,507	$423,466	$422,425	$421,384	$420,343	$419,302	$418,261	$417,220	$416,179	$415,138	$414,097	
6	Return on Average Net Investment (A)				426,069	425,028	423,987	422,946	421,905	420,864	419,823	418,782	417,741	416,700	415,659	414,618	
7	Return on Average Net Investment																
	a. Debt Component		1.83%		649	647	646	644	642	641	639	638	636	634	633	631	7,680
	b. Equity Component Grossed Up For Taxes		6.10%		2,164	2,159	2,154	2,149	2,143	2,138	2,133	2,127	2,122	2,117	2,111	2,106	25,623
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	2.4700%			1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	12,492
	b. Amortization				0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.000525			22	22	22	22	22	22	22	22	22	22	22	22	264
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$3,876	$3,869	$3,863	$3,856	$3,848	$3,842	$3,835	$3,828	$3,821	$3,814	$3,807	$3,800	$46,059
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,876	$3,869	$3,863	$3,856	$3,848	$3,842	$3,835	$3,828	$3,821	$3,814	$3,807	$3,800	$46,059

Note> Consistent with the Stipulation & Settlement Agreement in Order No. PSC-2013-0598-FOF-EI these assets were not projected to be in-service as of year end 2013 and accordingly were not moved to base rates in 2014.
(A) The allowable return is per the methodology approved in Order No. PSC-2020-0165-PAA-EU.

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
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Project Title: **Coal Combustion Residual (CCR) Rule**
Project No. 18

Project Description:
The Coal Combustion Residual (CCR) Rule was published in the Federal Register on 4/17/15 and is effective 10/19/15. This rule regulates the disposal of CCR as non-hazardous solid waste, and contains new requirements for CCR landfills and CCR surface impoundments. It also specifies implementation guidelines for compliance. The CCR compliance deadlines vary, with compliance obligations required as early as 10/19/15. The rule is self-implementing, meaning that affected facilities must comply with the new regulations irrespective of whether the rule is adopted by the State of Florida. The rule has specific impacts on the ash landfill, Flue Gas Desulfurization (FGD) lined blowdown ponds and temporary gypsum pad at the Crystal River site. No other DEF operating facilities are impacted by the CCR rule.

Project Accomplishments:
Annual inspections were completed for the FGD Blowdown Ponds and Ash Landfill. Maintenance, vegetation management, and weekly inspections for the FGD Blowdown Ponds and Ash Landfill continue. The groundwater assessment project for the FGD Blowdown Ponds and Ash Landfill continued per the requirements of the rule.

Project Fiscal Expenditures:
2020 estimated O&M expenditures are $917k. Capital forecast is $1.3M.

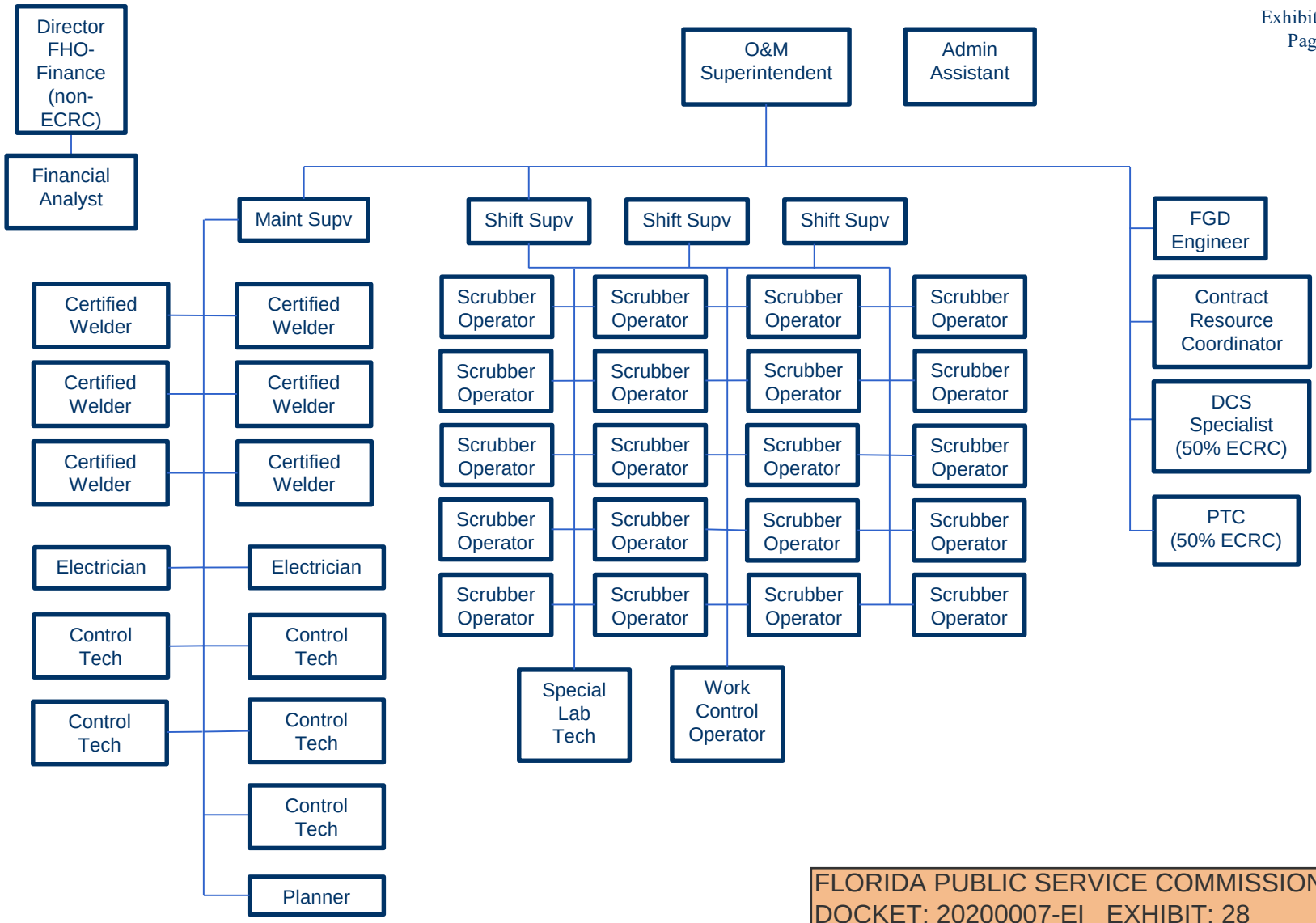
Project Progress Summary:
Ash Landfill: currently O&M work to remove some accumulated CCR material in the perimeter ditch, also some capital work after that for a new lined basin / ditch area, which will help avoid further accumulation in the future.

FGD Blowdown Ponds: Dewatering and solids removal from the primary and backup FGD Blowdown Ponds were completed. Development of a closure plan for the FGD Blowdown pond is underway. Pond closure was substantially completed during 2019, and alternative source demonstration was completed to address statistically significant increases in certain constituents in groundwater.

Vegetation Management & Inspection Work: More frequent mowing and inspection work is being performed, to comply with the CCR Rule.

Project Projections:
2021 estimated O&M expenditures are $278k, capital is forecasted to be $250k.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 27
PARTY: CAM-5 (27)
DESCRIPTION: Form 42-5P, page 23 of 23



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 28
PARTY: JS-1
DESCRIPTION: Crystal River Clean AirProjects Organizational Chart

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
Page 29 of 48

Project Title: **Integrated Clean Air Compliance Plan - Clean Air Interstate Rule (CAIR)**
Project Nos. (7.2, 7.3 & 7.4)

Project Description:
The Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant restrictions on emissions of SO_2 and NOx from power plants in 28 eastern states, including Florida and the District of Columbia. The CAIR rule apportions region-wide SO_2 and NOx emission reduction requirements to the individual states, and further requires each affected state to revise its State Implementation Plans (SIPs) to include measures necessary to achieve its emission reduction budget within prescribed deadlines.

The Cross-State air pollution Rule (CSAPR) replaced CAIR on 1/1/15. Under the CSAPR, the State of Florida is no longer required to comply with annual emission requirements, only NOx ozone seasonal limits. The CSAPR requirements took effect in Florida on 5/1/15, the beginning of the ozone season. NOx emission allowances under CAIR have no value; however, DEF will continue to use its SO2 emission allowances to comply with the Acid Rain Program. (see Project No. 5 - SO2 and NOx Emission Allowances Project Sheet for more information).

The Florida Department of Environmental Protection ("FDEP") Conditions of Certification, dated August 1, 2012, require DEF to evaluate an alternative disposal method of FGD Blowdown wastewater based on results of groundwater monitoring near percolation ponds. DEF is installing a physical/chemical treatment system to treat FGD Blowdown wastewater with discharge to surface water or percolation ponds.

Project Accomplishments:
The FGD Wastewater treatment (WWT) system went in-service February 2019.

Project Fiscal Expenditures:
For 2020, O&M expenditures for CAIR/CAMR – Peaking (Project 7.2) are projected to be $0. For the CAIR/CAMR Crystal River Program (Project 7.4), O&M is forecasted be $16.3M. Capital expenditures are forecasted to be $158k.

Project Progress Summary:
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

Project Projections:
2021 estimated O&M expenditures are $22.1M.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 29
PARTY: CAM-5 (29)
DESCRIPTION: Form 42-5P, pages 7, 21 and 22 of 23

Project Title: **Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion**
Project No. 17.1

Project Description:
Convert existing Anclote Units to use 100% natural gas to be in compliance with MATS as approved by the Commission in Order No. PSC-2012-0432-PAA-EI.

Project Accomplishments:
Unit 1 and Unit 2 gas conversions were completed 7/13/13 and 12/2/13, respectively. Unit 1 and Unit 2 Forced Draft (FD) fan modification work was completed 5/22/14 and 11/17/14, respectively.

Project Fiscal Expenditures:
No 2020 expenditures are expected for this project.

Project Progress Summary:
This project is in-service.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Mercury & Air Toxic Standards (MATS) CR1 & CR2**
Project No. 17.2

Project Description:
DEF implemented its CR1&2 MATS Compliance Plan as approved by the Commission in Order No. PSC-2014-0173-PAA-EI. CR1&2 have demonstrated compliance with all MATS requirements as of 4/16/2016.

Project Accomplishments:
DEF finalized its CR1&2 MATS Compliance Plan in December 2013 and began implementation in early 2014. Modifications were made to the electrostatic precipitators (ESPs) to improve particulate collection efficiency, and reagent injection systems were installed to reduce hydrogen chloride (HCl) and mercury emissions. Appendix K sorbent traps were installed for compliance demonstration with mercury emissions.

Project Fiscal Expenditures:
2020 O&M expenditures are expected to be $0k.

Project Progress Summary:
CR1&2 have been retired.

Project Projections:
DEF does not expect to incur any capital expenditures or O&M costs in 2021.

Duke Energy Florida, LLC

Review of Integrated Clean Air Compliance Plan

Submitted to the
Florida Public Service Commission

April 1, 2020



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 30
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Acronyms

BART – Best Available Retrofit Technology

CAIR – Clean Air Interstate Rule

CAMR – Clean Air Mercury Rule

CAVR – Clean Air Visibility Rule

CCR - Coal Combustion Residuals

CO_2 – Carbon Dioxide

CPP – Clean Power Plan

CSAPR – Cross-State Air Pollution Rule

DEF – Duke Energy Florida

ECRC – Environmental Cost Recovery Clause

EPA – Environmental Protection Agency

EGU – Electric Generating Unit

ELG - Effluent Limitation Guidelines

ESP – Electrostatic Precipitator

FDEP – Florida Department of Environmental Protection

FGD – Flue Gas Desulfurization

GHG – Greenhouse Gas

LNB – Low NO_x Burner

MATS – Mercury and Air Toxic Standards

MWh – Megawatt Hour

NAAQS – National Ambient Air Quality Standards

NO_x – Nitrogen Oxides

NPDES – National Pollutant Discharge Elimination System

NSPS - New Source Performance Standards

PAC – Powdered Activated Carbon

Plan D – DEF Integrated Clean Air Compliance Plan

PM – Particulate Matter

ppb – Parts per billion

PSC – Public Service Commission

SCR – Selective Catalytic Reduction

SIP – Site Implementation Plan

SO_2 – Sulfur Dioxide

Executive Summary

In the 2007 Environmental Cost Recovery Clause ("ECRC") Docket (No. 20070007-EI), the Commission approved Duke Energy Florida's ("DEF") updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of the Clean Air Interstate Rule ("CAIR") (subsequently replaced by the Cross-State Air Pollution Rule ("CSAPR"), Clean Air Mercury Rule ("CAMR") (subsequently replaced by the Mercury and Air Toxics Standards ("MATS") rule), Clean Air Visibility Rule ("CAVR"), and related regulatory requirements. In its 2007 final order, the Commission also directed DEF to file as part of its ECRC true-up testimony "a yearly review of the efficacy of its Plan D and the cost-effectiveness of DEF's retrofit options for each generating unit in relation to expected changes in environmental regulations." This report provides the required review for 2020.

The primary original components of DEF's 2006 Compliance Plan D included:

Sulfur Dioxide ("SO_2")

- Installation of flue gas desulfurization ("FGD") systems on Crystal River ("CR") Units 4 and 5
- Fuel switching at CR Units 1 and 2 to burn low sulfur coal
- Fuel switching at Anclote Units 1 and 2 to burn low sulfur oil and natural gas
- Purchases of SO_2 allowances

Nitrogen Oxides ("NO_x")

- Installation of low NO_x burners ("LNBs") and selective catalytic reduction ("SCR") systems on CR Units 4 and 5
- Installation of LNBs and separated over-fire air ("SOFA") or alternative NO_x controls at Anclote Units 1 and 2
- Purchase of annual and ozone season NO_x allowances

Mercury

- Installation of FGD and SCR systems at CR Units 4 and 5
- Installation of powdered activated carbon ("PAC") injection on CR Unit 2

As detailed in Docket No. 20070007-EI, DEF decided on Plan D based on a quantitative and qualitative evaluation of the ability of alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D is DEF's most cost-effective alternative to meet applicable regulatory requirements. The Plan was designed to strike a balance between reducing emissions, primarily through the installation of controls on DEF's largest and newest coal units (CR Units 4 and 5) and making strategic use of emission allowance markets.

In accordance with the Commission's final order in Docket No. 20070007-EI, DEF has continued to review the efficacy of Plan D and the cost-effectiveness of retrofit options in relation to expected changes in environmental regulations. With regard to efficacy, Plan D remains the cornerstone of DEF's efforts to comply with applicable air quality regulations in a cost-effective manner.

As indicated in previous ECRC filings, the U.S. Court of Appeals for the District of Columbia ("D.C. Circuit") stayed the effect of CSAPR (proposed by the U.S. Environmental Protection Agency ("EPA") to replace CAIR) leaving CAIR in effect until the court completed its review of CSAPR. In August 2012, the D.C. Circuit vacated CSAPR in its entirety, and in January 2013, the court denied EPA's petition for rehearing. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit's decision and upheld the CSAPR. EPA subsequently petitioned the D.C. Circuit to reinstate CSAPR, making it effective January 1, 2015. The court agreed with EPA and approved its petition.

Additionally, on February 16, 2012, EPA issued MATS to replace the vacated CAMR for emissions from coal- and oil-fired electric generating units ("EGUs"), including, potentially, DEF's Anclote Units 1 and 2, Suwannee Units 1, 2, and 3, and CR Units 1, 2, 4, and 5. The following summarizes the results of DEF's MATS compliance analyses for these units:

Anclote Units 1 & 2: DEF determined that the most cost-effective option for Anclote Units 1 and 2 was conversion to fire 100% natural gas rather than installation of emission controls

to comply with MATS. The Commission approved DEF's petition for ECRC recovery of costs associated with the Anclote Conversion Project in Docket No. 20120103-EI.

Suwannee Units 1, 2 & 3: DEF determined that no further modifications were needed on Suwannee Units 1, 2 and 3 as these units were already capable of operating on 100% natural gas.

CR Units 4 & 5: DEF determined that the existing electrostatic precipitators ("ESPs"), FGDs, and SCRs at CR Units 4 and 5 would provide sufficient control for MATS compliance under typical conditions. DEF also determined that chemical injection systems would be required to mitigate mercury re-emissions from the FGDs. On December 15, 2014, DEF requested a one-year extension to allow time for installation of additional mercury control systems. On March 12, 2015, the Florida Department of Environmental Protection ("FDEP") authorized a one-year extension (to April 16, 2016) for all mercury-related MATS requirements on CR Units 4 and 5; the units have operated in compliance with the Standards since that time.

CR Units 1 & 2: DEF determined that the use of alternative coals (along with dry sorbent injection, PAC injection, and ESP enhancements) was a feasible and cost-effective strategy to allow these units to continue running for a limited period of time in compliance with MATS and Best Available Retrofit Technology ("BART") requirements until new generation could be built. This plan was approved by the Commission in Order No. PSC-2014-0173-PAA-EI (April 17, 2014). On February 6, 2014, the FDEP granted a one-year extension (to April 16, 2016) for all MATS requirements on CR Units 1 and 2; the units have operated in compliance with the Standards since that time. CR Units 1 and 2 were retired from service on December 31, 2018.

Although EPA has begun implementation of a regulatory approach to reduce greenhouse gas ("GHG") emissions through the Clean Air Act, there currently are no GHG emission standards applicable to DEF's existing units. Moreover, there are still no retrofit options commercially available to reduce carbon dioxide ("CO_2") emissions from fossil fuel-fired EGUs. The Company will continue to monitor and update the Commission on EPA's efforts to establish emission guidelines to address GHG from existing power plants under Section 111(d) of the federal Clean Air Act and whether changes to EPA's approach occur.

DEF is confident that the emission controls installed pursuant to Plan D, along with compliance strategies discussed further in this Plan, will enable the Company to achieve and maintain compliance with all applicable environmental regulations in a cost-effective manner.

I. Introduction

In its final order in the 2007 ECRC Docket (No. 20070007-EI), the Commission approved DEF's updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of CAIR, CAMR, CAVR and related regulatory requirements. In *In re Environmental Cost Recovery Clause*, Order No. PSC-2007-0922-FOF-EI, p. 8 (Nov. 16, 2007), the Commission specifically found that "PEF's [now DEF's] updated Integrated Clean Air Compliance Plan represents the most cost-effective alternative for achieving and maintaining compliance with CAIR, CAMR, and CAVR, and related regulatory requirements, and it is reasonable and prudent for DEF to recover prudently incurred costs to implement the plan." *Id*. The Commission also directed DEF to file as part of its ECRC true-up testimony "a yearly review of the efficacy of its Plan D and the cost-effectiveness of [DEF's] retrofit options for each generating unit in relation to expected changes in environmental regulations." *Id*. The purpose of this report is to provide the required review for 2019.

II. Regulatory Background

The CAIR and CAVR programs required DEF and other utilities to significantly reduce emissions of SO_2 and NO_x. CAIR contemplated emission reductions in incremental phases, in which Phase I began in 2009 for NO_x and in 2010 for SO_2. Phase II was scheduled to begin in 2015 for both NO_x and SO_2. As noted later in this Plan, CAIR was remanded by the courts in 2008, but remained in place through 2014 while the EPA worked on development and implementation of an acceptable replacement rule. Following resolution of litigation, the replacement rule, CSAPR, took effect on January 1, 2015, and in 2016 was revised to exclude Florida. The CAVR, designed to improve visibility in Class I areas, remains in effect and the status of the BART requirements under CAVR affecting DEF is provided in part D of this section of this Plan. The CAMR originally required reduction of mercury emissions at a system level and installation of mercury monitors. As discussed later in this Plan, CAMR was vacated in early 2008 and in lieu of CAMR, EPA published a final MATS rule on February 16, 2012.

In March 2006, the Company submitted a report and supporting testimony presenting its integrated plan for complying with the CAIR, CAVR, and CAMR, as well as the process the

Company used to evaluate alternative plans, to the Commission. The analysis included an examination of the projected emissions associated with several alternative plans and a comparison of economic impacts, in terms of cumulative present value of revenue requirements. The Company's Integrated Clean Air Compliance Plan, designated as Plan D, was found to be the most cost-effective compliance plan for CAIR, CAMR, and CAVR from among five alternative plans.

In June 2007, the Company submitted an updated report and supporting testimony summarizing the status of the Plan and an updated economic analysis incorporating certain Plan revisions necessitated by changed circumstances. Consistent with the approach utilized in 2006, the Company performed a quantitative evaluation to compare the ability of modified alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D, as revised, is the Company's most cost-effective alternative to meet applicable regulatory requirements. Based on that analysis, the Commission approved Plan D as reasonable and prudent, and held that the Company should recover prudently incurred costs of implementing the Plan. In each subsequent ECRC docket, DEF has submitted its annual review of the Integrated Clean Air Compliance Plan for Commission review.

A. Status of CAIR and CSAPR

In July 2008, the D.C. Circuit issued a decision vacating CAIR in its entirety. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). However, the Court subsequently decided to remand CAIR without vacatur, thereby leaving the rule and its compliance obligations in place until EPA revises or replaces CAIR. *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008). EPA adopted the CSAPR to replace the CAIR by publication in the *Federal Register* in August 2011. *See* 76 Fed. Reg. 48,208 (Aug. 8, 2011).

In Order No. PSC-2011-0553-FOF-EI, issued in Docket No. 20110007-EI on December 7, 2011, the Commission addressed the impact of CSAPR on the Company's recovery of NO_x emission allowance costs. Because CSAPR would no longer allow the Company to use NO_x allowances previously obtained under CAIR for compliance effective January 1, 2012, the Commission established a regulatory asset to allow the Company to recover the costs of its remaining NO_x allowance inventory over a three-year amortization period. However, on December 30, 2011, the D.C. Circuit stayed CSAPR, leaving CAIR in effect until the court completed its review of the new rule. Thus, the Company continued to maintain its NO_x allowance

inventory in order to comply with CAIR. Pursuant to the stipulation approved in Order No. PSC-2011-0553-FOF-EI, the Company continued to expense NO_x allowance costs incurred to comply with CAIR based on actual usage consistent with current practice. In August 2012, the D.C. Circuit vacated CSAPR in its entirety, and in January 2013, the court denied EPA's petition for rehearing. *See EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7 (D.C. Cir. 2013). The EPA subsequently appealed the court's vacatur to the U.S. Supreme Court and on April 29, 2014, the Supreme Court overturned the D.C. Circuit's decision vacating CSAPR and remanded the case back to the lower court for further action. On June 26, 2014, the EPA requested that the court lift the stay of the CSAPR and allow it to be implemented, under a revised schedule, beginning January 1, 2015. This request was granted on October 23, 2014, and the CSAPR went into effect on January 1, 2015, replacing the CAIR. On July 28, 2015, the D.C. Circuit determined that EPA failed to cost justify a number of Phase 2 emission allowance budgets for certain states, including Florida, citing they were more stringent than necessary to achieve air compliance in downwind states, and held the Phase 2 NO_x allowance allocations invalid. Finally, on November 17, 2015, EPA proposed a revised CSAPR. EPA proposed to remove Florida from the CSAPR program, beginning with the 2017 ozone season.

On September 7, 2016, EPA finalized its CSAPR Update rule and eliminated Florida, South Carolina, and North Carolina from the CSAPR ozone season program based on modeling which shows that NO_x emissions from these states do not significantly contribute to ozone nonattainment in any downwind state. Duke Energy sources in Florida are no longer subject to any CSAPR NO_x emission limitations, as of the beginning of 2017.

B. Vacatur of CAMR and Adoption of MATS

In February 2008, the D.C. Circuit Court vacated CAMR and rejected EPA's delisting of coal-fired EGUs from the list of emission sources that are subject to Section 112 of the Clean Air Act. *See New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008). As a result, in lieu of CAMR, EPA was required to adopt new emissions standards for control of various hazardous air pollutant emissions from coal-fired EGUs. *Id*. EPA issued its proposed rule to replace CAMR on March 16, 2011, with publication following in the *Federal Register* on May 3, 2011. *See* 76 Fed. Reg. 24976 (May 3, 2011). On February 16, 2012, EPA published the final rule which established new MATS limits for emissions of various metals and acid gases from both coal- and oil-fired EGUs.

Compliance generally was required to be achieved within three years of EPA's adoption of MATS (i.e., April 16, 2015), although the Clean Air Act authorizes permitting authorities to grant one-year compliance extensions in certain circumstances. On June 29, 2015, the U.S. Supreme Court remanded the MATS rule to the D.C. Circuit, finding that the EPA insufficiently considered costs in determining that it is "appropriate and necessary" to regulate mercury from power plants. On December 15, 2015, the D.C. Circuit remanded the MATS rule to EPA without vacatur, and EPA committed to completing its consideration of cost by April 16, 2016. On March 3, 2016, the U.S. Supreme Court denied a request for a stay of the MATS rule while the EPA completes it cost consideration, thus the MATS rule remains in effect pending the cost consideration process. On March 18, 2016, a coalition of 20 states led by Michigan petitioned the Court for a writ of certiorari asking the Court to declare whether an administrative rule promulgated without statutory authority may be left in effect by a reviewing court during the pendency of its review. *See State of Mich., et al. v. EPA*, Pet. for Writ of Cert. to U.S. Sup. Ct. (filed Mar. 18, 2016). On April 14, 2016 EPA issued a final finding that it is appropriate and necessary to set standards for emissions of air toxics from coal- and oil-fired power plants. This finding responded to the decision by the U.S. Supreme Court that EPA must consider cost in the appropriate and necessary finding supporting MATS. This finding has been challenged.

On February 7, 2019 the EPA proposed a revision to its response to the U.S. Supreme Court decision in *Michigan v. EPA* which held that the EPA erred by not considering cost in its determination that regulation under section 112 of the Clean Air Act of hazardous air pollutant emissions from coal- and oil-fired electric utility steam generating units is appropriate and necessary. This proposal is currently under review.

In the 2011 ECRC docket, the Commission recognized that EPA's adoption of MATS for EGUs would require the Company to modify its Integrated Clean Air Compliance Plan. See Order No. PSC-2011-0553-FOF-EI, at 11. Accordingly, consistent with the Commission's expectation that utilities "take steps to control the level of costs that must be incurred for environmental compliance," Order No. PSC-2008-0775-FOF-EI, at 7, the Commission approved the Company's request to recover costs incurred to assess EPA's proposed rule, prepare comments to EPA, and develop compliance strategies within the aggressive regulatory timeframes proposed by EPA.

C. Greenhouse Gas Regulation

In 2007, then-Governor Crist issued Executive Order 07-127 directing the FDEP to promulgate regulations requiring reductions in utility CO_2 emissions. In addition, the 2008 Florida Legislature enacted legislation authorizing FDEP to adopt rules establishing a cap-and-trade program and requiring the FDEP to submit any such rules for legislative review and ratification. However, the FDEP did not adopt any cap-and-trade rules, and the Legislature subsequently repealed the 2008 law. Likewise, although a number of bills that would regulate GHG emissions have been introduced to Congress over the past several years, none have become law. In the meantime, the EPA has begun implementing a regulatory approach to reducing GHG emissions through the Clean Air Act. At this time, however, there are no GHG emission standards applicable to DEF's existing generating units. Moreover, there are still no retrofit options commercially available to reduce CO_2 emissions from fossil fuel-fired electric generating units such as CR Units 4 and 5, which are the primary focus of DEF's compliance plan. To date, there are very limited large-scale commercial carbon capture and storage technology demonstrations on electric utility units. Until numerous technological, regulatory, and liability issues are resolved, it will be impossible to determine whether carbon capture and storage would be a technically-feasible or cost-effective means of complying with a CO_2 regulatory regime. Moreover, replacing coal-fired generation from CR Units 4 and 5 with lower CO_2-emitting natural gas-fired combined cycle generation is not a viable option at this late date, particularly given the fact that DEF has placed in service Plan D components.

On June 25, 2013, President Obama issued a Presidential Memorandum directing the EPA to establish GHG emission guidelines for existing power plants under Section 111(d) of the Clean Air Act. The Presidential Memorandum directed the EPA to issue proposed GHG standards, regulations, or guidelines, as appropriate, for existing power plants by no later than June 1, 2014, and issue final standards, regulations or guidelines, as appropriate, by no later than June 1, 2015. In addition, the Presidential Memorandum directed the EPA to include a requirement in the new regulations that states submit State Implementation Plans ("SIPs") to implement the new guidelines by no later than June 30, 2016.

On August 3, 2015, the EPA released the final New Source Performance Standards ("NSPS") for CO_2 emissions from existing fossil fuel-fired EGUs (also known as the Clean Power Plan or "CPP"). The final CPP established state-specific emission goals; for Florida, the goals

begin a phased approach in 2022, ending with a rate goal of 919 lb. CO_2/MWh annual average for the period 2030 and beyond. Alternatively, the state can adopt a mass emissions approach culminating in a 2030 target of 105,094,704 tons (existing units) or 106,641,595 tons (existing plus new units). The final CPP has been challenged in the D.C. Circuit by 27 states and a number of industry groups. Oral argument occurred on September 27, 2016. The D.C. Circuit subsequently issued a stay of the litigation. Previously, on February 9, 2016, the U.S. Supreme Court had placed a stay on the CPP until such time that all litigation is completed.

Also, on August 3, 2015, the EPA released the final NSPS for CO_2 emissions from new, modified and reconstructed fossil fuel-fired EGUs. The rule includes emission limits of 1,400 lb. CO_2/MWh for new coal-fired units and 1,000 lb. CO_2/MWh for new natural gas combined-cycle units. This rule has also been challenged in the D.C. Circuit. The D.C. Circuit has issued an order suspending this litigation pending a review of the rule by EPA.

On March 28, 2017, President Trump signed an Executive Order ("EO") entitled "Promoting Energy Independence and Economic Growth." The EO directs federal agencies to "immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources." The EO specifically directs the EPA to review the following rules and determine whether to suspend, revise, or rescind those rules:

- The final CO_2 emission standards for existing power plants ("CPP");
- The final CO_2 emission standards for new power plants ("CO_2 NSPS");
- The proposed Federal Plan and Model Trading Rules that accompanied the CPP.

In response to the EO, the Department of Justice filed motions with the D.C. Circuit Court to stay the litigation of both the CPP and the CO_2 NSPS rules while each is reviewed by EPA. The EO does not change the current status of the CPP which is under a legal hold by the U.S. Supreme Court. With regard to the CO_2 NSPS, that rule will remain in effect pending the outcome of EPA's review.

On October 16, 2017, the EPA published a proposal to announce its intention to repeal the CPP. The proposal also requested public comment on the proposed rule. The EPA held public hearings on November 28 and 29, 2017, in Charleston, West Virginia, and extended the public comment period until January 16, 2018. In response to numerous requests for additional

opportunities for the public to provide oral testimony on the proposed rule in more than one location, the EPA will conduct EPA three listening sessions, and extend the public comment period until April 26, 2018.

On December 28, 2017 EPA published an Advanced Notice of Proposed Rulemaking (ANPR) to solicit information from the public as the agency considers proposing emission guidelines to limit GHG emissions from existing EGUs. EPA is also "soliciting information on the proper respective roles of the state and federal governments in the process, as well as information on systems of emission reduction that are applicable at or to an existing EGU, information on compliance measures, and information on state planning requirements under the Clean Air Act."

On June 19, 2019, EPA issued the Affordable Clean Energy rule ("ACE"), an effort to provide existing coal-fired electric utility generating units, or EGUs, with achievable and realistic standards for reducing greenhouse gas (GHG) emissions. This action was finalized in conjunction with two related, but separate and distinct rulemakings: (1) The repeal of the Clean Power Plan (CPP) and (2) Revised implementing regulations for ACE, ongoing emission guidelines, and all future emission guidelines for existing sources issued under the authority of Clean Air Act (CAA) section 111(d). ACE provides states with new emission guidelines that will inform the state's development of standards of performance to reduce carbon dioxide (CO2) emissions from existing coal-fired EGUs. ACE establishes heat rate improvement ("HRI"), or efficiency improvement, as the best system of emissions reduction ("BSER") for CO2 from coal-fired EGUs. ACE affected units for DEF include Crystal River Units 4 and 5. DEF is currently evaluating the impact of this rule.

D. Status of BART Requirements under CAVR

In 2009, the FDEP issued a permit imposing BART requirements for particulate matter ("PM") emissions from CR Units 1 and 2. The 2009 permit did not impose BART requirements for SO_2 and NO_x emissions because, at the time, the EPA assumed that compliance with CAIR would satisfy BART requirements for SO_2 and NO_x. Following the proposed adoption of CSAPR, in early 2012, the EPA revised its previous determination to replace the "CAIR satisfies BART" assumption with "CSAPR satisfies BART." In late 2011, CSAPR was vacated (although later re-instated – see part A above), leaving CAIR in effect and resulting in confusion regarding the ability

to rely on CAIR (or CSAPR) to satisfy BART requirements. As a result, in 2012, the Company worked with the FDEP to develop and finalize air construction permits to address SO_2 and NO_x emissions from CR Units 1 and 2 in support of FDEP's development of a revised Regional Haze SIP to address CAVR requirements for SO_2 and NO_x. The permits call for the installation of Dry FGD and SCR no later than January 1, 2018, or within 5 years of the effective date of the EPA's approval of the Florida Regional Haze SIP, whichever is later, or alternatively the discontinuation of the use of coal in CR Units 1 and 2 by December 31, 2020. DEF ultimately selected the latter of the two options. CR Units 1 and 2 were retired from service on December 31, 2018.

As discussed in the Company's 2013 Integrated Clean Air Compliance Plan, the FDEP subsequently submitted to EPA a revised Regional Haze SIP containing unit-specific determinations for SO_2 and NO_x, including the new permit requirements for CR Units 1 and 2. EPA formally approved the FDEP's revised Regional Haze SIP in August 2013. *See* 78 Fed Reg. 53250 (Aug. 29, 2013). Although third parties initially petitioned for review of EPA's approval in the U.S. Court of Appeals for the Eleventh Circuit, the petition was subsequently withdrawn and the SIP approval remains in place. CR Units 1 and 2 were retired from service on December 31, 2018.

E. Status of National Ambient Air Quality Standards (NAAQS)

The EPA and FDEP are working to implement the 2010 one-hour NAAQS for SO_2. In mid-2013, the EPA finalized nonattainment designations for two small areas in Florida outside of DEF's service territory (one in Nassau County, one in Hillsborough County) based on existing monitoring data. The EPA deferred making any area designations (attainment, nonattainment, or unclassifiable) for the remainder of the state. On August 21, 2015, the EPA published a final rule that describes requirements for additional ambient air quality monitoring and/or modeling that will be used to determine future rounds of area designations. Under the rule, the EPA made nonattainment designations in 2017 for modeled areas and in 2020, will make designations for monitored areas. Based on the EPA modeling protocol, the FDEP modeled the area surrounding the Crystal River facility and determined that future operation will not cause a nonattainment issue. This finding was provided to EPA on January 13, 2017, as part of the FDEP's Data Requirements Rule package submittal. On August 22, 2017, EPA issued the Intended Area Designation document, which did not concur with FDEP's recommendation and outlined EPA's intent to

identify an area in Citrus County near the Crystal River Power Plant as nonattainment with the SO2 ambient standard. FDEP provided additional updated information and, on December 21, 2017, EPA issued the final Third Round of SO2 Designations document designating the area around Crystal River as 'unclassifiable' rather than 'nonattainment.' In early 2018, this designation was upgrade to ‘attainment’, based on the results of the 2017 full year data.

In 2010, EPA also revised its NO_2 NAAQS to implement a new one-hour standard. At this time, however, DEF does not anticipate that the new standard will impact compliance measures at DEF facilities.

On October 1, 2015, the EPA issued a revised NAAQS for ambient ozone, changing the standard to 70 parts per billion (ppb) averaged over 8 hours from the previous level of 75 ppb. There are currently no nonattainment areas with respect to the revised standard in Florida; therefore, DEF does not anticipate an impact on its compliance measures.

III. DEF’s Integrated Clean Air Compliance Plan

The Company’s original compliance plan (Plan D) will continue to help it meet applicable environmental requirements by striking a balance between reducing emissions, primarily through installation of controls on its largest and newest coal units (CR Units 4 and 5). While the original plan made strategic use of the allowance markets to comply with CSAPR requirements, this is no longer necessary as discussed in Section II.A of this document. The controls installed in accordance with Plan D will continue to be the cornerstone of DEF’s compliance strategy with the adoption of MATS and other ongoing regulatory efforts. Specific components of the Plan are summarized below.

A. FGD Systems

The most significant component of DEF’s Integrated Clean Air Compliance Plan is the installation of FGD systems, also known as wet scrubbers, on CR Units 4 and 5 to comply with CAIR, Title IV of the Clean Air Act, and other SO_2 control requirements in DEF’s air permits for these units. The FGDs also reduce mercury and acid gasses and, therefore, are a key component of DEF’s MATS compliance strategy. In particular, the co-benefits of the FGDs and SCRs reduce mercury emissions by 90-95% under typical conditions.

B. SCR & Other NO_x Controls

The primary component of DEF's NO_x compliance plan is the installation of LNBs and SCR systems on CR Units 4 and 5. These controls enable DEF to comply with CAIR/CSAPR and other NO_x control requirements included in its air permits for the units. As discussed above, the SCRs also help achieve MATS requirements for mercury.

DEF has taken strategic advantage of CAIR's cap-and-trade feature by purchasing some annual and ozone season NO_x allowances; however, as explained above, the court stay of the CSAPR was lifted, and the rule went into effect replacing CAIR on January 1, 2015. Under the CSAPR, the State of Florida was only affected by the ozone season requirements of the rule, which applied from May through September. Beginning in 2017, the entire state of Florida was removed from the requirements to comply with the CSAPR. Consequently, DEF has NO_x CAIR emission allowances that cannot be used to comply with the CSAPR. DEF has established a regulatory asset to recover the costs of its remaining NO_x CAIR emission allowance inventory over a three-year amortization period beginning January 2015 in accordance with Order No. PSC-2011-0553-FOF-EI.

C. Additional MATS Compliance Strategies

DEF determined that the most cost-effective option for its Anclote Units 1 and 2 was conversion to fire 100% natural gas rather than installation of emission controls to comply with MATS. This was approved by the Commission in Docket 20120103-EI.

Suwannee Units 1, 2 and 3 operated exclusively on natural gas and, therefore, were not subject to MATS requirements. At the end of 2016, these units were retired.

DEF utilizes ESP, FGD, and SCR systems as the primary MATS control technologies for CR Units 4 and 5. In addition, DEF has installed chemical injection systems to mitigate mercury re-emissions from the FGDs.

For CR Units 1&2, DEF has determined that the use of alternative coals (along with dry sorbent injection, PAC injection, and ESP enhancements) is a feasible and cost-effective strategy to allow these units to continue running for a limited period of time in compliance with MATS and BART requirements until new generation can be built. This plan was approved by the Commission in Order No. PSC-2014-0173-PAA-EI (April 17, 2014). CR Units 1 and 2 were retired from service on December 31, 2018.

D. Visibility Requirements

DEF operates four units that are potentially subject to BART under CAVR: Anclote Units 1 and 2 and CR Units 1 and 2. Based on modeling of air emissions from Anclote Units 1 and 2, those units are exempt from BART for PM. Because the modeling results for CR Units 1 and 2 showed visibility impacts at or above regulatory threshold levels, DEF obtained a BART permit in 2009 for PM for those units. This permit established a combined BART PM emission standard for Crystal River Units 1 and 2 that requires demonstration of compliance by October 1, 2013. This deadline was met and the units now operate in compliance with the permit which was effective on January 1, 2014. As discussed above, in 2012 FDEP issued air construction permits addressing SO_2 and NO_x requirements for CR Units 1 and 2 in support of FDEP's development of a revised Regional Haze SIP. These units are also subject to the Reasonable Further Progress ("Beyond BART") requirements under CAVR which are now scheduled to take effect in 2021, following EPA's January 2017 extension of the 2018 requirements. As presented in the Company's petition approved in Order PSC-2014-0173-PAA-EI, DEF determined that the use of alternative coals with installation of less expensive pollution controls will provide a cost-effective means for it to continue operating CR Units 1 and 2 in compliance with MATS and CAVR for a limited time until replacement generation can be constructed.

IV. Efficacy of DEF's Plan

A. Project Milestones

DEF completed installation of Plan D's controls on CR Units 4 and 5 as contemplated in prior ECRC filings. CR Units 4 and 5 FGD and SCR projects are now in-service, and targeted environmental benefits have been met. In addition to reducing SO_2 and NO_x emissions, the FGDs and SCRs have the combined effect of reducing mercury and other emissions regulated by MATS. DEF installed mercury re-emission control systems in 2015 and has demonstrated compliance with the applicable MATS requirements for CR Units 4 and 5.

The Commission approved DEF's Need Petition in Docket No. 20140110-EI to construct the Citrus County Combined Cycle Units which are scheduled for commercial operation in 2018 and

allowed for the retirement of coal-fired CR Units 1 and 2. DEF installed pollution controls on CR Units 1 and 2 to allow for continued operation in compliance with MATS and BART until the Citrus units became operational. CR Units 1 and 2 were retired from service on December 31, 2018. Targeted environmental benefits have been met.

Anclote Units 1 and 2 were converted to fire 100% natural gas in 2013. Necessary upgrades to the forced draft fans were completed in 2014 in order to maintain unit output. Targeted environmental benefits have been met.

B. Projects

CR Units 4 and 5 FGD and SCR projects are now in-service, and the targeted environmental benefits have been met. The Anclote units have been converted to fire 100% natural gas. DEF operated CR Units 1 and 2 in compliance with BART and MATS requirements as outlined in Order No. PSC-2014-0173-PAA-EI until their retirement.

C. Uncertainties

The impacts of ongoing federal rulemaking activities on the compliance plan include:

- The final regulation on cooling water intake structures, Clean Water Act Section 316(b), will influence decisions with regard to control technologies to meet new standards. The rule was issued on May 19, 2014 with an effective date of October 14, 2014. New rule requirements are being assessed, and DEF's compliance strategies may be altered when this evaluation is complete. As identified in the September 1, 2017 filing in Docket No. 2017007-EI, DEF has selected a 316(b) compliance plan for Crystal River Units 1, 2, 4 and 5. Compliance with the 316(b) rule could result in the need for substantial capital improvements and/or plant modifications which could influence decisions with regard to control technologies to meet new standards at other affected stations. The compliance schedule for 316(b) is determined by each station's National Pollutant Discharge Elimination System ("NPDES") permit cycle.
- On September 30, 2015, the EPA finalized the updated Steam Electric Effluent Limitation Guidelines ("ELG") for electric power plants, with a publication date of November 3, 2015. Compliance with this rule will affect decisions associated with the treatment of wastewater generated by the wet FGDs, and discharges from the bottom

ash dewatering system at CR Units 4 and 5. On September 18, 2017, EPA issued a rule postponing for two (2) years the compliance dates for FGD wastewater and bottom ash transport water included in the 2015 rule.

- EPA signed the final CCR rule on December 19, 2014 and it was published on April 17, 2015. This rule will affect decisions associated with the handling of CCRs, including fly ash, bottom ash, and materials generated from operation of wet FGDs, including synthetic gypsum. DEF completed installation of 21 monitoring wells in December 2015 and January 2016. Sampling of these wells was performed and the results statistically analyzed in January 2018. DEF's current plan is, by April 15, 2018, to perform an alternate source demonstration for the FGD ponds and proceed with assessment monitoring for the ash storage / disposal area (ash landfill). All other applicable CCR rule requirements applicable to the FGD ponds and ash landfill will continue into 2020 and beyond.

V. Conclusion

DEF has completed installation of the emission controls contemplated in its approved Plan D on time and within budget. The FGD and SCR systems at CR Units 4 and 5 have enabled DEF to comply with CAIR, and subsequently the CSAPR requirements and will continue to be the cornerstone of DEF's integrated air quality compliance strategy for years to come. DEF is confident that Plan D, along with the other compliance strategies discussed in the document, has enabled the Company to achieve and maintain compliance with applicable regulations, including MATS, in a cost-effective manner.

Docket No. 20200007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Project Title: **Substation Environmental Investigation, Remediation and Pollution Prevention**
Project No. 1

Project Description:
Chapter 376 Florida Statutes requires that any person discharging a prohibited pollutant shall undertake to contain, remove and abate the discharge to the satisfaction of the FDEP. Similarly, Chapter 403 Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For DEF to comply with these statutes, it is actively conducting remediation and pollution prevention activities at its substation sites to remove the existence of pollutant discharges. Activities also include development and implementation of best management and pollution prevention measures at these sites.

Project Accomplishments:
The remediation portion of the Substation Assessment and Remedial Action Plan has been completed for all of the 279 SARAP substation sites. The Amended Deed Restrictive Covenant ("DRC") for West Lake Wales Substation has been approved by FDEP. The proposed DRC for Central Florida Substation submitted for approval to FDEP in July 2020.

Project Fiscal Expenditures:
2020 O&M expenditures for the substation system program (Projects 1 & 1a) are estimated to be $13k. Project 1, Transmission Substation Remediation, is forecasted to be $13k. Project 1a, Distribution Substation Remediation, is forecasted to be $157. The distribution portion of this program is now complete.

Project Progress Summary:
DEF continues to provide documentation for FDEP approval for the Substation Assessment and Remedial Action Plan (SARAP) and the Consent Order.

Project Projections:
2021 O&M estimated expenditures are $3,000.

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Project Title: **Distribution System Environmental Investigation, Remediation and Pollution Prevention**
Project No. 2

Project Description:
Chapter 376 Florida Statutes requires that any person discharging a prohibited pollutant shall undertake to contain, remove and abate the discharge to the satisfaction of the FDEP. Similarly, Chapter 403 Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For DEF to comply with these statutes, it is actively conducting remediation and pollution prevention activities at its distribution sites to remove the existence of pollutant discharges. Activities also include development and implementation of best management and pollution prevention measures at these sites.

Project Accomplishments:
All TRIP sites source removals are completed. The Final TRIP has been completed and the NAM report submitted to FDEP 4-4-19.

Project Fiscal Expenditures:
No further charges are expected to hit this project in 2020

Project Progress Summary:
This project is complete.

Project Projections:
No further charges are expected to hit this project in 2021.

Project Title: **Pipeline Integrity Management (PIM) - Bartow/Anclote Pipeline**
Project No. 3

Project Description:
The U.S. Department of Transportation (USDOT) Regulation 49 CFR Part 195, as amended effective 2/15/02, and the new regulation published at 67 Federal Register 2136 on 1/16/02, requires DEF to implement a PIM program. Prior to the 2/15/02 amendments, the USDOT's PIM regulations applied only to operators with 500 miles or more of hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on 2/15/02, extended the requirements for implementing integrity management to operators who have less than 500 miles of regulated pipelines. As such, DEF must maintain the integrity of pipeline systems in order to protect public safety and the environment, and comply with continual assessment and evaluation of pipeline systems integrity through inspection or testing, data integration and analysis, and follow up with remedial, preventative, and mitigative actions. DEF owns one hazardous liquid pipeline, Bartow/Anclote 14-inch hot oil pipeline, extending 33.3 miles from the Company's Bartow Plant north of St. Petersburg to the Anclote Plant in Holiday, that is subject to PIM regulations.

Effective 2/2010, amendments to 49 CFR 195 were finalized to improve opportunities to reduce risk through more effective control of pipelines. Compliance with these amendments will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue management. On 6/16/11, the USDOT published in the Federal Register (V0l. 76, 35130-35136), a final rule effective 8/15/11, that expedites the program implementation deadlines in the Control Room Management/Human Factors regulations in order to realize the safety benefits sooner than established in the original rule. This final rule amends the program implementation deadlines for different procedures to no later than 10/21/11 and 8/1/12.

Project Accomplishments:
Since the Bartow Anclote Pipeline (BAP) contained a small quantity of #6 fuel oil, the PIM program under 49CFR195 continues to be maintained. Third party projects by Florida Department of Transportation (FDOT), Florida Gas Transmission, Pinellas County, The City of Pinellas Park, and others have been evaluated for their risk to BAP integrity. Risk mitigation measures have been completed per 49CFR195.450. The BAP Risk Analysis has been updated. The Annual Report and National Pipeline Mapping System (NPMS) annual review have been completed. Reviews and evaluations are also being completed for Advisory Bulletins 11-04, 13-02, 15-01, and 15-02, relating to flooding and hurricanes. BAP personnel have participated in US Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA), utility owners groups, damage prevention groups, and FDOT workshops and training. Pipeline accidents and PHMSA enforcement actions have been reviewed for conditions that are applicable to the BAP and appropriate changes to BAP practices and procedures have been implemented. Pipeline records are being organized and stored with the conversion to electronic storage now essentially complete.

In 2016, pipeline ownership was transferred from the Fossil Hydro Operations group to Plant Retirement and Demolition, in preparation for pipeline retirement that is expected to occur in 2016. Once retired, the pipeline will be cleaned to remove any remaining oil. Once cleaned, the requirements described above in the PIM program will no longer be required. Cleaning is expected to occur in 2016, with any required demolition activities in 2017. As of the end of 2016, three of the four sub-projects were retired and approved to be amortized over three years - Project 3.1b Pipeline Leak Detection, Project 3.1c Pipeline Controls Upgrade, and Project 3.1d Control Room Management.

The final sub-project 3.1a - Alderman Road Fence was retired June 2017 and approved as a regulatory asset. This was amortized over 26 months, and all four parts of this project are fully amortized as of September 2019.

Project Fiscal Expenditures:
No capital or O&M expenditures are estimated for 2020.

Project Progress Summary:
Projects 3.1b (Pipeline leak Detection), 3.1c (Pipeline Controls Upgrade), and 3.1d (Control Room Management) were retired August 2016. Project 3.1a (Alderman Road Fence) retired June 2017. All are fully amortized as of September 2019.

Project Projections:
No capital or O&M expenditures are estimated for 2021.

Project Title: **Above Ground Storage Tank Secondary Containment**
Project No. 4

Project Description:
FDEP Rule 62-761.510(3) states that DEF is required to make improvements to its above ground petroleum storage tanks in order to comply with those provisions. Subsection (d) of the rule requires all internally lined single bottom above ground storage tanks to be upgraded with secondary containment, including secondary containment for piping in contact with the soil. Rule 62-761.500(1)(e) also requires that dike field area containment for pre-1998 tanks be upgraded, if needed, to comply with the requirement.

Project Accomplishments:
DEF has completed work at Debary 1 and 2, Turner 7, Turner 8, Higgins 1, and Bartow 6 as well as Turner P-1 and P-2 piping work.

Project Fiscal Expenditures:
No project expenditures are expected in 2020.

Project Progress Summary:
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications. Project 4.1a (Turner CTs) retired in March 2016.

Project Projections:
No new project expenditures are expected in 2021. DEF retired the Higgins combustion turbine plant December 2019, and expects to retire the Avon Park plant in 2020. With this retirement, the Above Ground Tank Secondary Containment and CAIR CT assets will also be retired. Consistent with Order No. PSC-2019-0500-FOF-EI, DEF is treating the unrecovered investments as a regulatory asset, and will amortize them over one year until fully recovered, with a return on the unamortized balance.

Project Title: **Phase II Cooling Water Intake**
Project No. 6

Project Description:
Section 316(b) of the Federal Clean Water Act requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. 33 U.S.C. Section 1326. On 5/19/14, the EPA Administrator signed a final 316(b) rule to protect fish and aquatic life drawn into cooling systems at power plant and factories. The rule aims to minimize impingement (aquatic life pinned against cooling water intake structures) and entrainment (aquatic life drawn into cooling water systems). The regulation became effective on October 14, 2014, 60 days after publication in the Federal Register which was 8/15/14.

EPA's regulation implementing §316(b) of the Clean Water Act for existing facilities was published on August 15, 2014. The regulation aims to minimize adverse environmental impacts to fish and other aquatic organisms from the operation of cooling water intake structures. The regulation became effective October 14, 2014, 60 days after publication in the Federal Register. The regulation primarily applies to existing power generating facilities that commenced construction prior to or on January 17, 2002 and to new units at existing facilities that are built to increase the generating capacity of the facility.

According to the current 316(b) rule, required studies and information submittals will be due with the renewal of the NPDES permit application for permits that expire after July 18, 2018. Permittees with a current NPDES permit that expires before July 18, 2018 may request the FDEP establish an alternative schedule for submitting the required information. This rule is applicable to Anclote, Bartow, Suwannee, and Crystal River North stations.

Project Accomplishments:
DEF is currently evaluating the 316(b) rule to determine potential study requirements, operating and cost impacts to its generating stations. Site specific strategic plans, studies, and implementation plans are under development to ensure compliance with all applicable requirements of the rule.

Project Fiscal Expenditures:
2020 O&M expenditures are estimated to be $305k. 2020 Capital expenditures are estimated to be $5.8M.

Project Progress Summary:
Required 316(b) reports have been finalized and will be submitted with the NPDES permit renewal applications to FDEP for review and approval . Anclote & Bartow reports have been filed with FDEP. Capital work at CRN continues with the addition of two CRN intake pumps, traveling screens and screen wash system, and intake structure modifications.

Project Projections:
2021 estimated O&M expenditures are $35k.

Project Title: **Integrated Clean Air Compliance Plan - Clean Air Interstate Rule (CAIR)**
Project Nos. (7.2, 7.3 & 7.4)

Project Description:
The Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant restrictions on emissions of SO_2 and NOx from power plants in 28 eastern states, including Florida and the District of Columbia. The CAIR rule apportions region-wide SO_2 and NOx emission reduction requirements to the individual states, and further requires each affected state to revise its State Implementation Plans (SIPs) to include measures necessary to achieve its emission reduction budget within prescribed deadlines.

The Cross-State air pollution Rule (CSAPR) replaced CAIR on 1/1/15. Under the CSAPR, the State of Florida is no longer required to comply with annual emission requirements, only NOx ozone seasonal limits. The CSAPR requirements took effect in Florida on 5/1/15, the beginning of the ozone season. NOx emission allowances under CAIR have no value; however, DEF will continue to use its SO2 emission allowances to comply with the Acid Rain Program. (see Project No. 5 - SO2 and NOx Emission Allowances Project Sheet for more information).

The Florida Department of Environmental Protection ("FDEP") Conditions of Certification, dated August 1, 2012, require DEF to evaluate an alternative disposal method of FGD Blowdown wastewater based on results of groundwater monitoring near percolation ponds. DEF is installing a physical/chemical treatment system to treat FGD Blowdown wastewater with discharge to surface water or percolation ponds.

Project Accomplishments:
The FGD Wastewater treatment (WWT) system went in-service February 2019.

Project Fiscal Expenditures:
For 2020, O&M expenditures for CAIR/CAMR – Peaking (Project 7.2) are projected to be $0. For the CAIR/CAMR Crystal River Program (Project 7.4), O&M is forecasted be $16.3M. Capital expenditures are forecasted to be $158k.

Project Progress Summary:
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program.

Project Projections:
2021 estimated O&M expenditures are $22.1M.

Project Title: **Best Available Retrofit Technology (BART)**
Project No. 7.5

Project Description:
On 5/25/12, the EPA proposed a partial disapproval of Florida's proposed Regional Haze State Implementation Plan (SIP) because the proposed SIP relies on CAIR to satisfy BART requirements for SO_2 and NOx emissions. CAIR remained in effect while litigation against the Cross State Air Pollution Rule (CSAPR) proceeded, and the EPA incorporated the CSAPR in place of CAIR into Regional Haze SIPs, including Florida. DEF worked with the FDEP to develop specific BART and Reasonable Progress permits for affected units that were incorporated into Florida's revised SIP submittal, which was filed with EPA on 9/17/12. The final BART permit applications for Crystal River fossil units were submitted to EPA on 10/15/12 as a supplement to the 9/17/12 submittal. Permitting was finalized in 2013 with an effective date of January 1, 2014.

Project Accomplishments:
DEF performed required emissions modeling and associated BART analysis for Crystal River 1&2 (CR1&2) and Anclote plants, developed and submitted a Reasonable Progress evaluation for Crystal River 4&5, developed and submitted necessary BART Implementation Plans and air construction permit applications in support of the FDEP's work to amend its SIP as directed by the EPA. Permitting actions were completed in 2013 with the effective date of the CR 1& 2 permit being January 1, 2014.

Project Fiscal Expenditures:
No project expenditures are expected in 2020.

Project Progress Summary:
DEF performed required emissions modeling and associated BART analysis for CR1&2 and Anclote, developed and submitted a Reasonable Progress evaluation for Crystal River 4&5, developed and submitted necessary BART Implementation Plans and air construction permit applications needed in support of the FDEP ongoing work to amend its State Implementation Plan as directed by the EPA. Based on the revised Regional Haze SIP incorporating the provisions of Crystal River's BART permits for SO_2 and NOx, EPA on 12/10/12 proposed approval of the SIP. In August 2013, EPA finalized the full approval of the SIP. The Crystal River South BART permit became effective on January 1, 2014 and DEF is now operating under the terms of that permit.

Project Projections:
No project expenditures are expected in 2021.

Project Title: **Arsenic Groundwater Standard**
Project No. 8

Project Description:
On 12/22/01, the EPA adopted a new maximum contaminant level (MCL) for arsenic in drinking water replacing the previous standard of 0.050 mg/L (50 ppb) with a new MCL of 0.010 mg/L (10 ppb). Effective 1/1/05, the FDEP established the USEPA MCL as Florida's drinking water standard. See Rule 62-550 F.A.C. The new standard has compliance implications for land application and water reuse projects in Florida with arsenic ground water monitoring levels above 10 ppb because the drinking water standard has been established as the groundwater standard by Rule 62-520-420(1), F.A.C.

Project Accomplishments:
A Plan of Study (POS) to evaluate the source of arsenic at the site was implemented on November 2011. A POS Addendum that included a leachability study and proposed abandoning one well and installing 3 new wells was implemented in February 2012. An additional Flue Gas Desulfurization (FGD) Wastewater Treatment Study was conducted in May 2013. The results of these studies indicated that Arsenic is naturally occurring in some areas but there is also a contribution from the FGD discharge from the lined treatment pond to the percolation ponds, and from the industrial wastewater from Crystal River Units 1 & 2. These sources are being addressed by the construction of a new FGD wastewater treatment system and retirement of Units 1 & 2, both scheduled to be completed by December 31, 2018.
Additional assessment was initiated in 2016 around the area of ground water wells still exceeding the Arsenic standard of 10 ppb with no clear source of Arsenic identified (MWC-1, MWC-31 and MWC-32). This additional assessment indicated that the source of Arsenic around MWC-31 is related to the former North Ash Pond that was located in that area. Based on that finding, the Consent Order was amended to address that area under 62-780, F.A.C. Remedial Actions, which included additional assessment and submittal of a final assessment report to FDEP in 2018.
Results from MWC-1 assessment indicate that the well is not measuring impacts from the industrial wastewater activities at the site and DEF requested to FDEP that the well be replaced by one of the Plan of Study wells. FDEP requested the sampling of all the wells around MWC-1 for a year prior to approval of the change. Assessment around MWC-32 is on-going in 2019.

Project Fiscal Expenditures:
2020 O&M expenditures are expected to be $1.2M.

Project Progress Summary:
Corrective actions are being implemented based on previous and continuing plan of studies.

Project Projections:
2021 O&M expenditures are forecasted to be $275k.

Project Title: **Sea Turtle - Coastal Street Lighting**
Project No. 9

Project Description:
DEF owns and leases high pressure sodium streetlights throughout its service territory, including areas along the Florida coast. Pursuant to Section 161.163, Florida Statutes, the FDEP, in collaboration with the Florida Fish and Wildlife Conservation Commission (FFWCC) and the U.S. Fish & Wildlife Service (USFWS), has developed a model Sea Turtle lighting ordinance. The model ordinance is used by the local governments to develop and implement ordinances within its jurisdiction. To date, Sea Turtle lighting ordinances have been adopted in Franklin County, Gulf County, City of Mexico Beach in Bay County and Pinellas County, all of which are within DEF's service territory. Since 2004, officials from the various local governments, as well as the FDEP, FFWC, and USFWS, have advised DEF that lighting it owns and leases is affecting turtle nesting areas that fall within the scope of these ordinances. As a result, local governments require DEF to take additional measures to satisfy new criteria being applied to ensure compliance with the sea turtle ordinances.

Project Accomplishments:
DEF continues to work with Franklin County, Gulf County, City of Mexico Beach in Bay County, and Pinellas County to mitigate any potential sea turtle nesting issues by retrofitting existing street lights, placing amber shields on existing HPS street lights and monitoring street lights for effectiveness in complying with sea turtle ordinances.

Project Fiscal Expenditures:
2020 Capital expenditures are estimated to be $0, O&M expenditures are estimated to be a $0.

Project Progress Summary:
DEF is on schedule with activities identified for this program.

Project Projections:
2021 estimated O&M is $600, and Capital expenditures are estimated at $600.

Project Title: **Underground Storage Tanks**
Project No. 10

Project Description:
FDEP regulations require that underground pollutant storage tanks and small diameter piping be upgraded with secondary containment by 12/31/09. See Rule 62-761.510(5), F.A.C. DEF identified four tanks that must comply with this rule: two at Crystal River Plant and two at Bartow Plant.

Project Accomplishments:
Work on Crystal River and Bartow USTs was completed in 4th Qtr 2006.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Modular Cooling Towers**
Project No. 11

Project Description:
This project involves installation and operation of modular cooling towers in the summer months to minimize de-rates of Crystal River 1&2 (CR1&2) necessary to comply with the NPDES permit limit for the temperature of cooling water discharged from the units.

Project Accomplishments:
Vendors of modular cooling towers were evaluated regarding cost of installation and operation. The FDEP reviewed the project and approved operation. A vendor was selected and the towers were installed during the 2nd Qtr 2006.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
The modular cooling towers began operation in June 2006 and successfully minimized de-rates of CR 1&2. The towers were removed during the first half of 2012. This project is complete.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Crystal River Thermal Discharge Compliance Project**
Project No. 11.1

Project Description:
This project was to evaluate and implement the best long term solution to maintain compliance with the thermal discharge limit in the FDEP industrial wastewater permit for Crystal River Units 1,2&3 that was being addressed in the short term by the Modular Cooling Towers approved in Docket No. 20060162-EI. Due to DEF's decision to retire CR3, this project is no longer necessary and will not be implemented.

Project Accomplishments:
The study phase of the project was completed with a recommendation to replace the leased modular cooling towers in coordination with the cooling solution for the CR3 Extended Power Uprate (EPU) discharge canal cooling solution. The new cooling tower associated with the CR3 EPU was to be sized to mitigate both increased temperatures from the EPU as well as replace the modular cooling towers, which were removed in 2012. The design contract for the CR3 EPU cooling tower was awarded and a vendor selected. In February 2013, DEF decided to retire CR3; therefore, the project will not proceed.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
Crystal River Units 1,2&3 utilize a once-through cooling water process to cool and condense turbine exhaust steam back to water. The cooling water is removed from the Gulf of Mexico via an intake canal and discharged to a common discharge canal shared by all of the generating units. DEF has a NPDES industrial wastewater permit from the FDEP to discharge this cooling water from CR 1,2&3 into the Gulf of Mexico. The FDEP NPDES permit includes a limit on the temperature of the cooling water discharge (96.5 degrees Fahrenheit on a three-hour rolling average) measured at the point of discharge to the Gulf of Mexico. The new cooling towers were being added as a long term solution to the issue of higher ambient water temperatures previously being addressed by the modular cooling towers and added heat rejection due to the estimated 180MW Uprate of CR3. With the retirement of CR3, the heat rejection associated with the entire unit is removed and therefore the new cooling tower is not necessary for the continued operation of CR 1&2 within the NPDES permit limits.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Greenhouse Gas (GHG) Inventory and Reporting**
Project No. 12

Project Description:
The GHG Inventory and Reporting Program was created in response to Chapter 2008-277, Florida Laws, which established the Florida Climate Protection Act to be codified at section 403.44, Florida Statutes. Among other things, this legislation authorizes the FDEP to establish a cap and trade program for GHG emissions from power plants. Utilities subject to the program, including DEF, will be required to use The Climate Registry for purposes of GHG emission registration and reporting. The requirement to report to The Climate Registry was repealed during the 2010 legislative session; however, the EPA GHG Reporting Rule (40 CFR 98) does require DEF to submit 2010 GHG data to the EPA no later than 9/30/2011.

Project Accomplishments:
In 2009, DEF joined The Climate Registry and submitted 2008 GHG inventory data. 2009 data was submitted during the third quarter of 2010. Both 2008 and 2009 data was validated by a third party as required by The Climate Registry. 2010 GHG inventory data was submitted to EPA on 9/30/11 and EPA does not require data validation by a third party. DEF has discontinued its membership with The Climate Registry. Since third party validation is not required by the EPA, no future expenditures will be incurred by DEF, resulting in the completion of this project.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
DEF submits GHG inventory data directly to EPA which does not require third party validation. Membership with The Climate Registry has been discontinued.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Mercury Total Daily Maximum Loads Monitoring (TMDL)**
Project No. 13

Project Description:
Section 303(d) of the Federal Clean Water Act requires each state to identify state waters not meeting water quality standards and establish a TMDL for the pollutant or pollutants causing the failure to meet standards. Under a 1999 federal consent decree, TMDLs for over 100 Florida water bodies listed as impaired for mercury must be established by 9/12/12. The FDEP has initiated a research program to provide necessary information for setting appropriate TMDLs for mercury. Among other things, the study will assess the relative contributions of mercury-emitting sources, such as coal-fired power plants, to mercury levels in surface waters.

Project Accomplishments:
Atmospheric & Environmental Research, Inc (AER) completed the literature review on mercury deposition in Florida. This document was sent to the FDEP Division of Air Resource Management and the TMDL team for review in February 2009. In addition, the Florida Electric Power Coordinating Group (FCG) Mercury Task Force met with FDEP Division of Air Resource Management to discuss the review in January 2010. AER performed Florida mercury deposition modeling for the Division of Air Resource Management. The FCG Mercury Task Force contracted with Tetra Tech to conduct aquatic field sampling, including an aquatics modeling report, to develop a "Conceptual Model for the Florida Mercury TMDL." This document was finalized and submitted to the FDEP in December 2010. Key personnel from AER were employed by Environ in 2011 and FCG established a contract with Environ to ensure continuity of the project. FCG used Environ and Tetra Tech to review and critique FDEP's aquatic cycling and atmospheric modeling analyses. The FDEP developed a mercury TMDL report in the spring and summer of 2012, and it proposed a TMDL in September 2012. The EPA approved Florida's statewide mercury TMDL in a letter dated October 18, 2013. Florida's mercury TMDL covers 441 waters listed as impaired for mercury based on fish tissue mercury levels. EPA's approval letter states that if FDEP identifies any new waters to be listed as impaired for mercury, a new TMDL will not be required if the listing is caused by the factors addressed in the approved TMDL. Conversely, a new TMDL, addressing the newly listed water body, would be required if "local emission or effluent sources" are determined to be the cause of the elevated fish tissue levels that required the new listing.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
The mercury TMDL study concluded in 2012.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Hazardous Air Pollutants (HAPs) ICR Program**
Project No. 14

Project Description:
In 2009, the EPA initiated efforts to develop an Information Collection Request (ICR), which requires that owners/operators of all coal- and oil-fired electric utility steam generating units provide information that will allow the EPA to assess emissions of hazardous air pollutants from each such unit. The intention of the ICR is to assist the Administrator of the EPA in developing national emission standards for hazardous air pollutants under Section 112(d) of the Clean Air Act, 42 U.S.C. 7412. Pursuant to those efforts, by letter dated 12/24/09, the EPA formally requested DEF comply with certain data collection and emissions testing requirements for several of its steam electric generating units. The EPA letter states that initial submittal of existing information must be made within 90 days, and that the remaining data must be submitted within 8 months. Collection and submittal of the requested information is mandatory under Section 114 of the Clean Air Act, 42 U.S.C. 7414.

Project Accomplishments:
DEF completed and submitted the ICR to EPA during 2010. The HAPS ICR project is complete.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA during 2010.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Effluent Limitation Guidelines ICR Program**
Project No. 15

Project Description:
The Effluent Limitation Guidelines ICR Program was created in response to Section 304 of the Federal Clean Water Act which directs the EPA to develop and periodically review regulations, called effluent guidelines, to limit the amount of pollutants that are discharged to surface waters from various point source categories. 33 U.S.C. §13 14(b). In October 2009, the EPA announced that it intended to update the effluent guidelines for the steam electric power generating point source category, which were last updated in 1982. DEF is required to complete the ICR and submit responses to the EPA within 90 days. Collection and submittal of the requested information is mandatory under Section 308 of the Clean Water Act.

Project Accomplishments:
DEF completed and submitted the ICR to the EPA in September 2010. The Effluent Limitation Guidelines ICR Program is complete.

Project Fiscal Expenditures:
There are no 2020 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA in September 2010.

Project Projections:
No 2021 expenditures are expected for this project.

Project Title: **Effluent Limitation Guidelines CRN Program**
Project No. 15.1

Project Description:
On September 30th, 2015, U.S. Environmental Protection Agency finalized the Steam Electric Power Generating Effluent Guidelines, 40 CFR Part 423, imposing federal standards on several power plant streams that are discharged to surface water. In the final regulation, closed-loop systems or dry handling have been identified as the Best Available Technology ("BAT") for bottom ash transport water. Crystal River North Units 4 & 5 have a dry bottom ash system that utilizes dewatering bins for separation of bottom ash and water. However, the current configuration has the potential for bottom ash transport water to leave via overflows and drain into an NPDES internal outfall. Achieving the closed loop bottom ash compliance requirement is as soon as possible beginning November 1, 2018 but no later than December 31, 2023. Renewal of the Crystal River Units 4 & 5 NPDES permit is in progress and addresses this requirement. Duke Energy is seeking a compliance date of February 1, 2020 to include modification of the existing system.

Project Accomplishments:
DEF Initiated the first phase of ELG compliance activities necessary to comply with NPDES permit renewal. The remaining project scope is still on hold pending EPA Administrative Stay final decision.

Project Fiscal Expenditures:
The 2020 Capital forecast is $231k.

Project Progress Summary:
This project was placed in-service June 2020.

Project Projections:
No capital or O&M expenditures are forecasted for 2021.

Project Title: **National Pollutant Discharge Elimination System (NPDES)**
Project No. 16

Project Description:
Pursuant to the Federal Clean Water Act, 33 U.S.C. § 1342, all point source discharges to navigable waters from industrial facilities must obtain permits under the NPDES Program. The FDEP administers the NPDES program in Florida. DEF's Anclote, Bartow, and Crystal River North, Crystal River South, and Suwannee NPDES permits were issued on 11/25/2015, 1/5/2016, 7/18/11, 4/7/2014, and 10/6/2016, respectively. Crystal River North NPDES permit is in the renewal process. All facilities are required to meet new permitting conditions. In Docket No. 20110007-EI, the Commission approved recovery of costs associated with new requirements included or expected to be included in the new renewal permits, including: thermal studies, aquatic organism return studies and implementation, whole effluent toxicity testing, dissolved oxygen (DO) studies (Bartow only), and freeboard limitation related studies (Bartow only). As noted in DEF's 2/8/12 program update, on 12/14/11, the FDEP issued a final NPDES renewal permit and associated Administrative Order (AO) for the Suwannee Plant. The AO includes a new requirement to assess copper discharges that DEF did not anticipate when it filed its petition in 2011.

Project Accomplishments:
DEF continues to perform whole effluent toxicity testing, implementing initial 316(b) rule requirements based on NPDES permit schedules at affected facilities which includes literature review and analysis, additional field study, and reporting requirements in accordance to NPDES permit requirements. Bartow freeboard limitation study was completed in May 2011 and submitted to FDEP on 6/23/11. The FDEP approved DEF's corrective action plan and Bartow is in compliance with Administrative Order as of December 2014. The copper discharge study at the Suwannee plant has been completed and a final report was submitted to the FDEP in June 2014 resulting in a corrective action of retiring the steam units. The Suwannee plant retired Units 1, 2 and 3 in December 2016.

Project Fiscal Expenditures:
2020 O&M expenditures are estimated to be $30k. No capital expenditures are forecasted for 2020.

Project Progress Summary:
DEF has begun complying with the requirements of the NPDES permits. Aquatic organism return study requirements have been postponed to align with the final EPA 316(b) rule requirements (Bartow/Anclote Plants) which was published 8/15/14. The aquatic organism return requirement is not a requirement in the Crystal River North NPDES permit. The dissolved oxygen study of cooling water intake and discharge at the Bartow plant was completed and the results of the study demonstrated there is no negative impact on DO due to the plant's operation. The final DO report was submitted to the FDEP on November 20, 2012, and the Department has not required any additional action. The Suwannee Steam station was retired and removed from service; therefore, WET testing is no longer required.

Project Projections:
2021 estimated O&M expenditures are $32k. No capital expenditures are expected in 2021.

Project Title: **Mercury & Air Toxic Standards (MATS) CR4 & CR5**
Project No. 17

Project Description:
The Commission approved ECRC recovery of DEF's costs for compliance with new hazardous air pollutant standards at Crystal River Units 4 & 5 (CR4&5) in Order No. PSC-2011-0553-FOF-EI. The final MATS rule was issued by the EPA on 12/21/11. The FDEP granted a limited, one-year extension for the mercury-related requirements on 3/12/15. DEF will utilize the co-benefits of existing FGD and SCR systems as the primary MATS emission controls. CR4&5 have demonstrated compliance with all MATS requirements as of 4/16/16.

Project Accomplishments:
DEF installed oxidation-reduction potential (ORP) probes and mercury re-emission control systems for MATS emissions control. In addition, continuous emissions monitoring systems (CEMS) were installed for compliance demonstration with particulate matter (PM) and mercury emissions. Appendix K sorbent traps have been certified and maintained to serve as backup monitors for mercury CEMS.

Project Fiscal Expenditures:
2020 O&M expenditures are estimated to be $360K.

Project Progress Summary:
Initial implementation of the CR4&5 MATS compliance plan is complete.

Project Projections:
2021 estimated O&M is $120k. No capital expenditures are forecasted.

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TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2019 THROUGH DECEMBER 2019

FORMS 42-1A THROUGH 42-9A

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 32
PARTY: MAS-1
DESCRIPTION: Final Environmental Cost Recovery Commission Forms 42-1A through 42-9A for the period January 2019 t...

Tampa Electric Company

Form 42 - 1A

Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019
(in Dollars)

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2019 to December 2019 (Form 42-2A, Lines 5 + 6 + 10)	$8,096,350
2.	Actual/Estimated True-Up Amount Approved for the Period January 2019 to December 2019 (Order No. PSC-2019-0500-FOF-EI)	4,108,435
3.	Final True-Up to be Refunded/(Recovered) in the Projection Period January 2021 to December 2021 (Lines 1 - 2)	$3,987,915

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Current Period True-Up Amount
(in Dollars)

Line	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1. ECRC Revenues (net of Revenue Taxes)	$3,117,973	$3,107,867	$3,079,732	$3,044,137	$3,638,503	$4,162,521	$4,248,611	$4,133,273	$4,417,060	$3,990,360	$3,645,862	3,033,987	$43,619,884
2. True-Up Provision	1,247,596	1,247,596	1,247,596	1,247,596	1,247,596	1,247,596	1,247,596	1,247,596	1,247,596	1,247,596	1,247,596	1,247,593	14,971,149
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	4,365,569	4,355,463	4,327,328	4,291,733	4,886,099	5,410,117	5,496,207	5,380,869	5,664,656	5,237,956	4,893,458	4,281,580	58,591,033
4. Jurisdictional ECRC Costs													
a. O & M Activities (Form 42-5A, Line 9)	653,838	325,229	529,258	703,070	491,154	326,112	214,044	307,492	265,396	361,434	393,688	1,117,623	5,688,338
b. Capital Investment Projects (Form 42-7A, Line 9)	3,777,690	3,768,918	3,759,531	3,749,850	3,740,331	3,730,330	3,787,200	3,776,638	3,766,081	3,756,237	3,745,670	3,735,333	45,093,809
c. Total Jurisdictional ECRC Costs	4,431,528	4,094,147	4,288,789	4,452,920	4,231,485	4,056,442	4,001,244	4,084,130	4,031,477	4,117,671	4,139,358	4,852,956	50,782,147
5. Over/(Under) Recovery (Line 3 - Line 4c)	(65,959)	261,316	38,539	(161,188)	654,614	1,353,675	1,494,963	1,296,739	1,633,179	1,120,285	754,100	(571,376)	7,808,887
6. Interest Provision (Form 42-3A, Line 10)	33,588	31,344	29,637	27,160	24,673	23,630	22,552	21,499	21,279	19,353	17,035	15,713	287,463
7. Beginning Balance True-Up & Interest Provision	14,971,149	13,691,182	12,736,246	11,556,826	10,175,202	9,606,893	9,736,602	10,006,521	10,077,163	10,484,025	10,376,067	9,899,606	14,971,149
a. Deferred True-Up from January to December 2018 (Order No. PSC-2019-0500-FOF-EI)	**2,396,214**	2,396,214	2,396,214	2,396,214	2,396,214	2,396,214	2,396,214	2,396,214	2,396,214	2,396,214	2,396,214	2,396,214	2,396,214
8. True-Up Collected/(Refunded) (see Line 2)	(1,247,596)	(1,247,596)	(1,247,596)	(1,247,596)	(1,247,596)	(1,247,596)	(1,247,596)	(1,247,596)	(1,247,596)	(1,247,596)	(1,247,596)	(1,247,593)	(14,971,149)
9. End of Period Total True-Up (Lines 5+6+7+7a+8)	16,087,396	15,132,460	13,953,040	12,571,416	12,003,107	12,132,816	12,402,735	12,473,377	12,880,239	12,772,281	12,295,820	10,492,564	10,492,564
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)	$16,087,396	$15,132,460	$13,953,040	$12,571,416	$12,003,107	$12,132,816	$12,402,735	$12,473,377	$12,880,239	$12,772,281	$12,295,820	$10,492,564	$10,492,564

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Form 42 - 3A

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$17,367,363	$16,087,396	$15,132,460	$13,953,040	$12,571,416	$12,003,107	$12,132,816	$12,402,735	$12,473,377	$12,880,239	$12,772,281	$12,295,820	
2.	Ending True-Up Amount Before Interest	16,053,808	15,101,116	13,923,403	12,544,256	11,978,434	12,109,186	12,380,183	12,451,878	12,858,960	12,752,928	12,278,785	10,476,851	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	33,421,171	31,188,512	29,055,863	26,497,296	24,549,850	24,112,293	24,512,999	24,854,613	25,332,337	25,633,167	25,051,066	22,772,671	
4.	Average True-Up Amount (Line 3 x 1/2)	16,710,586	15,594,256	14,527,932	13,248,648	12,274,925	12,056,147	12,256,500	12,427,307	12,666,169	12,816,584	12,525,533	11,386,336	
5.	Interest Rate (First Day of Reporting Business Month)	2.42%	2.41%	2.41%	2.48%	2.43%	2.39%	2.32%	2.10%	2.05%	1.97%	1.66%	1.60%	
6.	Interest Rate (First Day of Subsequent Business Month)	2.41%	2.41%	2.48%	2.43%	2.39%	2.32%	2.10%	2.05%	1.97%	1.66%	1.60%	1.71%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	4.83%	4.82%	4.89%	4.91%	4.82%	4.71%	4.42%	4.15%	4.02%	3.63%	3.26%	3.31%	
8.	Average Interest Rate (Line 7 x 1/2)	2.415%	2.410%	2.445%	2.455%	2.410%	2.355%	2.210%	2.075%	2.010%	1.815%	1.630%	1.655%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.201%	0.201%	0.204%	0.205%	0.201%	0.196%	0.184%	0.173%	0.168%	0.151%	0.136%	0.138%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$33,588	$31,344	$29,637	$27,160	$24,673	$23,630	$22,552	$21,499	$21,279	$19,353	$17,035	$15,713	$287,463

DOCKET NO. 20200007-EI
ECRC 2019 FINAL TRUE-UP
EXHIBIT MAS-1, DOC. NO. 3, PAGE 1 OF 1

Tampa Electric Company Form 42 - 4A

Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Percent
1.	Description of O&M Activities				
	a. Big Bend Unit 3 FGD Integration	$401,848	$481,495	($79,647)	-16.5%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	-	-	-	0.0%
	c. SO_2 Emissions Allowances	4	(22)	26	-117.4%
	d. Big Bend Units 1 & 2 FGD	111,549	134,789	(23,240)	-17.2%
	e. Big Bend PM Minimization and Monitoring	271,350	307,226	(35,876)	-11.7%
	f. Big Bend NO_x Emissions Reduction	4,591	9,306	(4,715)	-50.7%
	g. NPDES Annual Surveillance Fees	34,512	34,500	12	0.0%
	h. Gannon Thermal Discharge Study	-	-	-	0.0%
	i. Polk NO_x Emissions Reduction	103	-	103	0.0%
	j. Bayside SCR Consumables	122,799	126,480	(3,681)	-2.9%
	k. Big Bend Unit 4 SOFA	-	-	-	0.0%
	l. Big Bend Unit 1 Pre-SCR	7,482	9,757	(2,275)	-23.3%
	m. Big Bend Unit 2 Pre-SCR	19,460	5,260	14,200	270.0%
	n. Big Bend Unit 3 Pre-SCR	15,340	17,525	(2,185)	-12.5%
	o. Clean Water Act Section 316(b) Phase II Study	15,996	30,286	(14,291)	-47.2%
	p. Arsenic Groundwater Standard Program	18,227	4,511	13,716	304.0%
	q. Big Bend 1 SCR	68,114	93,819	(25,706)	-27.4%
	r. Big Bend 2 SCR	252,727	165,455	87,272	52.7%
	s. Big Bend 3 SCR	353,242	496,632	(143,390)	-28.9%
	t. Big Bend 4 SCR	1,213,571	1,387,011	(173,440)	-12.5%
	u. Mercury Air Toxics Standards	7,456	7,633	(177)	-2.3%
	v. Greenhouse Gas Reduction Program	93,149	93,149	-	0.0%
	w. Big Bend Gypsum Storage Facility (East 40)	1,110,282	1,262,594	(152,311)	-12.1%
	x. Big Bend CCR Rule - Phase I	12,019	3,949	8,069	204.3%
	y. Big Bend ELG Compliance	34,065	30,601	3,464	11.3%
	z. Big Bend CCR Rule - Phase II	1,520,453	4,401,681	(2,881,228)	-65.5%
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	-	-	-	0.0%
2.	Total Investment Projects - Recoverable Costs	$5,688,338	$9,103,637	($3,415,300)	-37.5%
3.	Recoverable Costs Allocated to Energy	$5,619,603	$9,034,339	($3,414,737)	-37.8%
4.	Recoverable Costs Allocated to Demand	$68,735	$69,298	($563)	-0.8%

Notes:

Column (1) is the End of Period Totals on Form 42-5A.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2019-0500-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Form 42 - 5A

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 FGD Integration	$21,689	$13,379	$21,539	$40,931	$85,891	$73,066	$17,248	$24,142	$36,443	$31,033	$11,273	$25,213	$401,848		$401,848
	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	8	12	5	(6)	(85)	7	(5)	13	14	(3)	26	17	4		4
	d. Big Bend Units 1 & 2 FGD	22,680	24,872	2,316	1,855	4,073	18,993	2,728	21,885	1,732	284	9,441	690	111,549		111,549
	e. Big Bend PM Minimization and Monitoring	5,426	6,832	34,527	32,499	25,357	16,586	21,612	30,554	(4,024)	95,765	(7,123)	13,340	271,350		271,350
	f. Big Bend NO_x Emissions Reduction	31	108	3,128	39	0	0	145	924	114	0	101	0	4,591		4,591
	g. NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	12	0	0	0	34,512	$34,512	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	i. Polk NO_x Emissions Reduction	0	0	0	0	0	0	0	0	0	0	0	103	103		103
	j. Bayside SCR and Ammonia	12,903	3,255	14,383	11,967	8,446	14,525	13,781	14,256	3,255	11,045	11,727	3,255	122,799		122,799
	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	725	5,672	360	0	0	0	725	0	0	0	7,482		7,482
	m. Big Bend Unit 2 Pre-SCR	0	0	815	0	1,445	0	14,283	0	1,377	725	0	815	19,460		19,460
	n. Big Bend Unit 3 Pre-SCR	588	12,724	1,213	0	0	0	0	0	0	815	0	0	15,340		15,340
	o. Clean Water Act Section 316(b) Phase II Study	0	0	4,605	0	0	1,093	4,928	0	870	0	0	4,500	15,996	15,996	
	p. Arsenic Groundwater Standard Program	0	0	4,511	0	0	0	0	0	3,516	6,769	3,430	0	18,227	18,227	
	q. Big Bend 1 SCR	684	4,888	26,042	9,422	2,068	1,279	1,176	1,190	6,089	964	13,214	1,097	68,114		68,114
	r. Big Bend 2 SCR	22,002	23,385	(4,554)	4,641	11,944	1,441	107	7,293	33,319	9,531	61,752	81,866	252,727		252,727
	s. Big Bend 3 SCR	15,859	30,392	81,819	13,385	128,902	24,963	(40,914)	9,445	13,008	30,032	17,653	28,698	353,242		353,242
	t. Big Bend 4 SCR	87,112	57,926	54,358	214,259	158,324	76,377	58,692	74,530	108,464	130,889	92,866	99,773	1,213,571		1,213,571
	u. Mercury Air Toxics Standards	5,633	0	0	0	0	0	1,687	0	0	24	0	112	7,456		7,456
	v. Greenhouse Gas Reduction Program	0	0	0	93,149	0	0	0	0	0	0	0	0	93,149		93,149
	w. Big Bend Gypsum Storage Facility (East 40)	103,370	94,019	87,637	162,622	83,680	71,267	99,355	70,557	55,675	43,178	176,073	62,851	1,110,282		1,110,282
	x. Big Bend CCR Rule - Phase I	1,612	4,575	0	364	443	1,602	0	1,341	0	384	943	755	12,019		12,019
	y. Big Bend ELG Compliance	11,819	0	0	14,239	0	4,542	0	3,464	0	0	0	0	34,065		34,065
	z. Big Bend CCR Rule - Phase II	307,923	48,862	196,186	98,032	(19,693)	20,370	19,220	47,897	4,805	0	2,312	794,538	1,520,453		1,520,453
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	653,838	325,229	529,258	703,070	491,154	326,112	214,044	307,492	265,396	361,434	393,688	1,117,623	5,688,338	$68,735	$5,619,603
3.	Recoverable Costs Allocated to Energy	619,338	325,229	520,142	703,070	491,154	325,019	209,116	307,492	260,998	354,665	390,258	1,113,123	5,619,603		
4.	Recoverable Costs Allocated to Demand	34,500	0	9,116	0	0	1,093	4,928	0	4,398	6,769	3,430	4,500	68,735		
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)	619,338	325,229	520,142	703,070	491,154	325,019	209,116	307,492	260,998	354,665	390,258	1,113,122	5,619,603		
8.	Jurisdictional Demand Recoverable Costs (B)	34,500	0	9,116	0	0	1,093	4,928	0	4,398	6,769	3,430	4,501	68,735		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$653,838	$325,229	$529,258	$703,070	$491,154	$326,112	$214,044	$307,492	$265,396	$361,434	$393,688	$1,117,623	$5,688,338		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DOCKET NO. 20200007-EI
ECRC 2019 FINAL TRUE-UP
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Tampa Electric Company Form 42 - 6A

Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 FGD Integration	$937,334	$942,371	($5,037)	-0.5%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	235,155	235,507	(352)	-0.1%
	c. Big Bend Unit 4 Continuous Emissions Monitors	49,116	49,297	(181)	-0.4%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	73,107	73,205	(98)	-0.1%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	120,237	120,399	(162)	-0.1%
	f. Big Bend Unit 1 Classifier Replacement	76,546	76,749	(203)	-0.3%
	g. Big Bend Unit 2 Classifier Replacement	55,464	55,626	(162)	-0.3%
	h. Big Bend Section 114 Mercury Testing Platform	8,320	8,361	(41)	-0.5%
	i. Big Bend Units 1 & 2 FGD	5,829,734	5,852,617	(22,883)	-0.4%
	j. Big Bend FGD Optimization and Utilization	1,557,845	1,566,247	(8,402)	-0.5%
	k. Big Bend NO_x Emissions Reduction	491,943	495,092	(3,149)	-0.6%
	l. Big Bend PM Minimization and Monitoring	1,759,203	1,767,965	(8,762)	-0.5%
	m. Polk NO_x Emissions Reduction	109,563	110,041	(478)	-0.4%
	n. Big Bend Unit 4 SOFA	192,999	193,988	(989)	-0.5%
	o. Big Bend Unit 1 Pre-SCR	132,974	133,545	(571)	-0.4%
	p. Big Bend Unit 2 Pre-SCR	126,694	127,276	(582)	-0.5%
	q. Big Bend Unit 3 Pre-SCR	226,595	227,710	(1,115)	-0.5%
	r. Big Bend Unit 1 SCR	7,596,735	7,629,840	(33,105)	-0.4%
	s. Big Bend Unit 2 SCR	8,304,599	8,343,405	(38,806)	-0.5%
	t. Big Bend Unit 3 SCR	6,759,073	6,790,879	(31,806)	-0.5%
	u. Big Bend Unit 4 SCR	5,407,302	5,433,692	(26,390)	-0.5%
	v. Big Bend FGD System Reliability	2,053,069	2,065,157	(12,088)	-0.6%
	w. Mercury Air Toxics Standards	803,102	808,174	(5,072)	-0.6%
	x. $S0_2$ Emissions Allowances	(2,598)	(2,622)	24	-0.9%
	y. Big Bend Gypsum Storage Facility (East 40)	2,033,675	2,045,696	(12,021)	-0.6%
	z. Big Bend CCR Rule - Phase I	106,261	111,772	(5,511)	-4.9%
	aa. Big Bend CCR Rule - Phase II	40,643	41,119	(476)	-1.2%
	ab. Big Bend ELG Compliance	7,618	7,519	99	1.3%
	ac. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	1,501	11,910	(10,409)	-87.4%
2.	Total Investment Projects - Recoverable Costs	$45,093,809	$45,322,537	($228,728)	-0.5%
3.	Recoverable Costs Allocated to Energy	$44,785,085	$44,964,132	($212,072)	-0.5%
4.	Recoverable Costs Allocated to Demand	$349,367	$365,924	($16,557)	-4.5%

Notes:

Column (1) is the End of Period Totals on Form 42-7A.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2019-0500-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-7A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description (A)		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 FGD Integration	1	$78,310	$78,131	$77,951	$77,772	$77,593	$77,414	$78,823	$78,638	$78,453	$78,268	$78,083	$77,898	$937,334		$937,334
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	20,097	19,997	19,897	19,796	19,695	19,595	19,605	19,502	19,398	19,294	19,191	19,088	235,155		235,155
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	4,144	4,129	4,115	4,101	4,086	4,072	4,115	4,101	4,085	4,071	4,056	4,041	49,116		49,116
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4	6,253	6,222	6,189	6,158	6,126	6,094	6,093	6,060	6,027	5,995	5,961	5,929	73,107	$73,107	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	5	10,284	10,232	10,180	10,127	10,075	10,023	10,021	9,967	9,913	9,859	9,805	9,751	120,237	120,237	
	f.	Big Bend Unit 1 Classifier Replacement	6	6,498	6,471	6,444	6,416	6,389	6,362	6,398	6,370	6,342	6,313	6,285	6,258	76,546		76,546
	g.	Big Bend Unit 2 Classifier Replacement	7	4,701	4,683	4,663	4,645	4,625	4,606	4,639	4,619	4,600	4,580	4,561	4,542	55,464		55,464
	h.	Big Bend Section 114 Mercury Testing Platform	8	697	695	693	692	689	688	699	697	695	694	691	690	8,320		8,320
	i.	Big Bend Units 1 & 2 FGD	9	491,226	489,598	487,970	486,343	484,716	483,089	488,667	486,986	485,306	483,625	481,944	480,264	5,829,734		5,829,734
	j.	Big Bend FGD Optimization and Utilization	10	129,898	129,694	129,453	129,302	129,006	128,709	131,062	130,756	130,450	130,144	129,838	129,533	1,557,845		1,557,845
	k.	Big Bend NO_x Emissions Reduction	11	40,849	40,786	40,722	40,659	40,596	40,532	41,463	41,398	41,333	41,267	41,201	41,137	491,943		491,943
	l.	Big Bend PM Minimization and Monitoring	12	147,315	146,936	146,558	146,180	145,802	145,423	147,808	147,417	147,027	146,636	146,246	145,855	1,759,203		1,759,203
	m.	Polk NO_x Emissions Reduction	13	9,207	9,179	9,152	9,124	9,096	9,069	9,193	9,165	9,137	9,109	9,080	9,052	109,563		109,563
	n.	Big Bend Unit 4 SOFA	14	16,147	16,108	16,068	16,029	15,988	15,948	16,221	16,180	16,139	16,098	16,057	16,016	192,999		192,999
	o.	Big Bend Unit 1 Pre-SCR	15	11,181	11,146	11,112	11,078	11,043	11,010	11,155	11,120	11,085	11,049	11,015	10,980	132,974		132,974
	p.	Big Bend Unit 2 Pre-SCR	16	10,634	10,604	10,574	10,543	10,513	10,483	10,635	10,604	10,573	10,542	10,510	10,479	126,694		126,694
	q.	Big Bend Unit 3 Pre-SCR	17	18,981	18,931	18,882	18,833	18,783	18,734	19,036	18,985	18,934	18,883	18,832	18,781	226,595		226,595
	r.	Big Bend Unit 1 SCR	18	638,489	636,568	634,648	632,727	630,806	628,886	637,395	635,411	633,427	631,443	629,459	627,476	7,596,735		7,596,735
	s.	Big Bend Unit 2 SCR	19	696,688	694,748	692,807	690,866	688,925	686,984	697,274	695,270	693,266	691,261	689,257	687,253	8,304,599		8,304,599
	t.	Big Bend Unit 3 SCR	20	566,921	565,355	563,789	562,223	560,657	559,091	567,550	565,933	564,315	562,697	561,080	559,462	6,759,073		6,759,073
	u.	Big Bend Unit 4 SCR	21	452,878	451,728	450,614	449,526	448,337	447,143	454,267	453,032	451,797	450,562	449,327	448,091	5,407,302		5,407,302
	v.	Big Bend FGD System Reliability	22	170,515	170,402	170,188	170,008	169,712	169,404	172,955	172,639	172,308	171,977	171,646	171,315	2,053,069		2,053,069
	w.	Mercury Air Toxics Standards	23	66,807	66,830	66,692	66,553	66,415	66,276	67,576	67,433	67,290	67,190	67,091	66,949	803,102		803,102
	x.	SO_2 Emissions Allowances (B)	24	(213)	(213)	(213)	(213)	(213)	(213)	(220)	(220)	(220)	(220)	(220)	(220)	(2,598)		(2,598)
	y.	Big Bend Gypsum Storage Facility (East 40)	25	169,363	169,041	168,718	168,395	168,073	167,751	171,221	170,889	170,556	170,223	169,889	169,556	2,033,675		2,033,675
	z.	Big Bend CCR Rule - Phase I	26	7,355	7,729	7,973	8,208	8,857	9,052	9,215	9,235	9,174	9,822	9,826	9,815	106,261	106,261	
	aa.	Big Bend CCR Rule - Phase II	27	2,221	2,749	3,184	3,222	3,315	3,389	3,552	3,596	3,679	3,763	3,838	4,135	40,643	40,643	
	ab.	Big Bend ELG Compliance	28	244	439	508	532	609	682	719	740	758	768	780	839	7,618	7,618	
	ac.	Big Bend Unit 1 Sec. 316(b) Impingement Mortality	29	0	0	0	5	17	34	63	115	234	324	341	368	1,501	1,501	
2.		Total Investment Projects - Recoverable Costs		3,777,690	3,768,918	3,759,531	3,749,850	3,740,331	3,730,330	3,787,200	3,776,638	3,766,081	3,756,237	3,745,670	3,735,333	45,093,809	$349,367	$44,744,442
3.		Recoverable Costs Allocated to Energy		3,751,333	3,741,547	3,731,497	3,721,598	3,711,332	3,701,056	3,757,537	3,746,925	3,736,296	3,725,706	3,715,119	3,704,496	44,744,442		44,744,442
4.		Recoverable Costs Allocated to Demand		26,357	27,371	28,034	28,252	28,999	29,274	29,663	29,713	29,785	30,531	30,551	30,837	349,367	349,367	
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)		3,751,333	3,741,547	3,731,497	3,721,598	3,711,332	3,701,056	3,757,537	3,746,925	3,736,296	3,725,706	3,715,119	3,704,496	44,744,442		
8.		Jurisdictional Demand Recoverable Costs (D)		26,357	27,371	28,034	28,252	28,999	29,274	29,663	29,713	29,785	30,531	30,551	30,837	349,367		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$3,777,690	$3,768,918	$3,759,531	$3,749,850	$3,740,331	$3,730,330	$3,787,200	$3,776,638	$3,766,081	$3,756,237	$3,745,670	$3,735,333	$45,093,809		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Project's Total Return Component on Form 42-8A, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

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ECRC 2019 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Form 42-8A

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	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	
3.	Less: Accumulated Depreciation	(5,786,337)	(5,815,175)	(5,844,013)	(5,872,851)	(5,901,689)	(5,930,527)	(5,959,365)	(5,988,203)	(6,017,041)	(6,045,879)	(6,074,717)	(6,103,555)	(6,132,393)	
4.	CWIP - Non-Interest Bearing	-	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,976,926	7,948,088	7,919,250	7,890,412	7,861,574	7,832,736	7,803,898	7,775,060	7,746,222	7,717,384	7,688,546	7,659,708	7,630,870	
6.	Average Net Investment		7,962,507	7,933,669	7,904,831	7,875,993	7,847,155	7,818,317	7,789,479	7,760,641	7,731,803	7,702,965	7,674,127	7,645,289	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$38,096	$37,958	$37,820	$37,682	$37,544	$37,406	$38,710	$38,567	$38,424	$38,281	$38,137	$37,994	$456,619
	b. Debt Component Grossed Up For Taxes (C)		11,376	11,335	11,293	11,252	11,211	11,170	11,275	11,233	11,191	11,149	11,108	11,066	134,659
8.	Investment Expenses														
	a. Depreciation (D)		28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	346,056
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		78,310	78,131	77,951	77,772	77,593	77,414	78,823	78,638	78,453	78,268	78,083	77,898	937,334
	a. Recoverable Costs Allocated to Energy		78,310	78,131	77,951	77,772	77,593	77,414	78,823	78,638	78,453	78,268	78,083	77,898	937,334
	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)		78,310	78,131	77,951	77,772	77,593	77,414	78,823	78,638	78,453	78,268	78,083	77,898	937,334
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)		$78,310	$78,131	$77,951	$77,772	$77,593	$77,414	$78,823	$78,638	$78,453	$78,268	$78,083	$77,898	$937,334

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775), 315.45 ($327,307), and 312.40 ($182)
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5%, 3.1%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(4,372,970)	(4,389,111)	(4,405,252)	(4,421,393)	(4,437,534)	(4,453,675)	(4,469,816)	(4,485,957)	(4,502,098)	(4,518,239)	(4,534,380)	(4,550,521)	(4,566,662)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$644,764	628,623	612,482	596,341	580,200	564,059	547,918	531,777	515,636	499,495	483,354	467,213	451,072	
6.	Average Net Investment		636,694	620,553	604,412	588,271	572,130	555,989	539,848	523,707	507,566	491,425	475,284	459,143	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,046	$2,969	$2,892	$2,815	$2,737	$2,660	$2,683	$2,603	$2,522	$2,442	$2,362	$2,282	$32,013
	b. Debt Component Grossed Up For Taxes (C)		910	887	864	840	817	794	781	758	735	711	688	665	9,450
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)		20,097	19,997	19,897	19,796	19,695	19,595	19,605	19,502	19,398	19,294	19,191	19,088	235,155
	a. Recoverable Costs Allocated to Energy		20,097	19,997	19,897	19,796	19,695	19,595	19,605	19,502	19,398	19,294	19,191	19,088	235,155
	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)		20,097	19,997	19,897	19,796	19,695	19,595	19,605	19,502	19,398	19,294	19,191	19,088	235,155
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)		$20,097	$19,997	$19,897	$19,796	$19,695	$19,595	$19,605	$19,502	$19,398	$19,294	$19,191	$19,088	$235,155

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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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ECRC 2019 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(569,885)	(572,195)	(574,505)	(576,815)	(579,125)	(581,435)	(583,745)	(586,055)	(588,365)	(590,675)	(592,985)	(595,295)	(597,605)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$296,326	294,016	291,706	289,396	287,086	284,776	282,466	280,156	277,846	275,536	273,226	270,916	268,606	
6.	Average Net Investment		295,171	292,861	290,551	288,241	285,931	283,621	281,311	279,001	276,691	274,381	272,071	269,761	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,412	$1,401	$1,390	$1,379	$1,368	$1,357	$1,398	$1,387	$1,375	$1,364	$1,352	$1,341	$16,524
	b. Debt Component Grossed Up For Taxes (C)		422	418	415	412	408	405	407	404	400	397	394	390	4,872
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)		4,144	4,129	4,115	4,101	4,086	4,072	4,115	4,101	4,085	4,071	4,056	4,041	49,116
	a. Recoverable Costs Allocated to Energy		4,144	4,129	4,115	4,101	4,086	4,072	4,115	4,101	4,085	4,071	4,056	4,041	49,116
	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)		4,144	4,129	4,115	4,101	4,086	4,072	4,115	4,101	4,085	4,071	4,056	4,041	49,116
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)		$4,144	$4,129	$4,115	$4,101	$4,086	$4,072	$4,115	$4,101	$4,085	$4,071	$4,056	$4,041	$49,116

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2019 FINAL TRUE-UP
EXHIBIT MAS-1, DOC. NO. 8, PAGE 3 OF 29

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(313,150)	(318,273)	(323,396)	(328,519)	(333,642)	(338,765)	(343,888)	(349,011)	(354,134)	(359,257)	(364,380)	(369,503)	(374,626)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$184,428	179,305	174,182	169,059	163,936	158,813	153,690	148,567	143,444	138,321	133,198	128,075	122,952	
6.	Average Net Investment		181,867	176,744	171,621	166,498	161,375	156,252	151,129	146,006	140,883	135,760	130,637	125,514	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$870	$846	$821	$797	$772	$748	$751	$726	$700	$675	$649	$624	$8,979
	b. Debt Component Grossed Up For Taxes (C)		260	253	245	238	231	223	219	211	204	197	189	182	2,652
8.	Investment Expenses														
	a. Depreciation (D)		5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,476
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,253	6,222	6,189	6,158	6,126	6,094	6,093	6,060	6,027	5,995	5,961	5,929	73,107
	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		6,253	6,222	6,189	6,158	6,126	6,094	6,093	6,060	6,027	5,995	5,961	5,929	73,107
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)		6,253	6,222	6,189	6,158	6,126	6,094	6,093	6,060	6,027	5,995	5,961	5,929	73,107
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,253	$6,222	$6,189	$6,158	$6,126	$6,094	$6,093	$6,060	$6,027	$5,995	$5,961	$5,929	$73,107

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(515,062)	(523,488)	(531,914)	(540,340)	(548,766)	(557,192)	(565,618)	(574,044)	(582,470)	(590,896)	(599,322)	(607,748)	(616,174)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$303,339	294,913	286,487	278,061	269,635	261,209	252,783	244,357	235,931	227,505	219,079	210,653	202,227	
6.	Average Net Investment		299,126	290,700	282,274	273,848	265,422	256,996	248,570	240,144	231,718	223,292	214,866	206,440	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,431	$1,391	$1,351	$1,310	$1,270	$1,230	$1,235	$1,193	$1,152	$1,110	$1,068	$1,026	$14,767
	b. Debt Component Grossed Up For Taxes (C)		427	415	403	391	379	367	360	348	335	323	311	299	4,358
8.	Investment Expenses														
	a. Depreciation (D)		8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	101,112
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,284	10,232	10,180	10,127	10,075	10,023	10,021	9,967	9,913	9,859	9,805	9,751	120,237
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		10,284	10,232	10,180	10,127	10,075	10,023	10,021	9,967	9,913	9,859	9,805	9,751	120,237
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)		10,284	10,232	10,180	10,127	10,075	10,023	10,021	9,967	9,913	9,859	9,805	9,751	120,237
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,284	$10,232	$10,180	$10,127	$10,075	$10,023	$10,021	$9,967	$9,913	$9,859	$9,805	$9,751	$120,237

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(974,504)	(978,892)	(983,280)	(987,668)	(992,056)	(996,444)	(1,000,832)	(1,005,220)	(1,009,608)	(1,013,996)	(1,018,384)	(1,022,772)	(1,027,160)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$341,753	337,365	332,977	328,589	324,201	319,813	315,425	311,037	306,649	302,261	297,873	293,485	289,097	
6.	Average Net Investment		339,559	335,171	330,783	326,395	322,007	317,619	313,231	308,843	304,455	300,067	295,679	291,291	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,625	$1,604	$1,583	$1,562	$1,541	$1,520	$1,557	$1,535	$1,513	$1,491	$1,469	$1,448	$18,448
	b. Debt Component Grossed Up For Taxes (C)		485	479	473	466	460	454	453	447	441	434	428	422	5,442
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)		6,498	6,471	6,444	6,416	6,389	6,362	6,398	6,370	6,342	6,313	6,285	6,258	76,546
	a. Recoverable Costs Allocated to Energy		6,498	6,471	6,444	6,416	6,389	6,362	6,398	6,370	6,342	6,313	6,285	6,258	76,546
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		6,498	6,471	6,444	6,416	6,389	6,362	6,398	6,370	6,342	6,313	6,285	6,258	76,546
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,498	$6,471	$6,444	$6,416	$6,389	$6,362	$6,398	$6,370	$6,342	$6,313	$6,285	$6,258	$76,546

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(715,302)	(718,338)	(721,374)	(724,410)	(727,446)	(730,482)	(733,518)	(736,554)	(739,590)	(742,626)	(745,662)	(748,698)	(751,734)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$269,492	266,456	263,420	260,384	257,348	254,312	251,276	248,240	245,204	242,168	239,132	236,096	233,060	
6.	Average Net Investment		267,974	264,938	261,902	258,866	255,830	252,794	249,758	246,722	243,686	240,650	237,614	234,578	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,282	$1,268	$1,253	$1,239	$1,224	$1,209	$1,241	$1,226	$1,211	$1,196	$1,181	$1,166	$14,696
	b. Debt Component Grossed Up For Taxes (C)		383	379	374	370	365	361	362	357	353	348	344	340	4,336
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)		4,701	4,683	4,663	4,645	4,625	4,606	4,639	4,619	4,600	4,580	4,561	4,542	55,464
	a. Recoverable Costs Allocated to Energy		4,701	4,683	4,663	4,645	4,625	4,606	4,639	4,619	4,600	4,580	4,561	4,542	55,464
	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)		4,701	4,683	4,663	4,645	4,625	4,606	4,639	4,619	4,600	4,580	4,561	4,542	55,464
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)		$4,701	$4,683	$4,663	$4,645	$4,625	$4,606	$4,639	$4,619	$4,600	$4,580	$4,561	$4,542	$55,464

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2019 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(55,411)	(55,703)	(55,995)	(56,287)	(56,579)	(56,871)	(57,163)	(57,455)	(57,747)	(58,039)	(58,331)	(58,623)	(58,915)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$65,326	65,034	64,742	64,450	64,158	63,866	63,574	63,282	62,990	62,698	62,406	62,114	61,822	
6.	Average Net Investment		65,180	64,888	64,596	64,304	64,012	63,720	63,428	63,136	62,844	62,552	62,260	61,968	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$312	$310	$309	$308	$306	$305	$315	$314	$312	$311	$309	$308	$3,719
	b. Debt Component Grossed Up For Taxes (C)		93	93	92	92	91	91	92	91	91	91	90	90	1,097
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)		697	695	693	692	689	688	699	697	695	694	691	690	8,320
	a. Recoverable Costs Allocated to Energy		697	695	693	692	689	688	699	697	695	694	691	690	8,320
	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)		697	695	693	692	689	688	699	697	695	694	691	690	8,320
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)		$697	$695	$693	$692	$689	$688	$699	$697	$695	$694	$691	$690	$8,320

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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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ECRC 2019 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	
3.	Less: Accumulated Depreciation	(58,217,237)	(58,479,156)	(58,741,075)	(59,002,994)	(59,264,913)	(59,526,832)	(59,788,751)	(60,050,670)	(60,312,589)	(60,574,508)	(60,836,427)	(61,098,346)	(61,360,265)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$37,038,005	36,776,086	36,514,167	36,252,248	35,990,329	35,728,410	35,466,491	35,204,572	34,942,653	34,680,734	34,418,815	34,156,896	33,894,977	
6.	Average Net Investment		36,907,045	36,645,126	36,383,207	36,121,288	35,859,369	35,597,450	35,335,531	35,073,612	34,811,693	34,549,774	34,287,855	34,025,936	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$176,579	$175,326	$174,072	$172,819	$171,566	$170,313	$175,603	$174,301	$173,000	$171,698	$170,396	$169,095	$2,074,768
	b. Debt Component Grossed Up For Taxes (C)		52,728	52,353	51,979	51,605	51,231	50,857	51,145	50,766	50,387	50,008	49,629	49,250	611,938
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)		491,226	489,598	487,970	486,343	484,716	483,089	488,667	486,986	485,306	483,625	481,944	480,264	5,829,734
	a. Recoverable Costs Allocated to Energy		491,226	489,598	487,970	486,343	484,716	483,089	488,667	486,986	485,306	483,625	481,944	480,264	5,829,734
	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)		491,226	489,598	487,970	486,343	484,716	483,089	488,667	486,986	485,306	483,625	481,944	480,264	5,829,734
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)		$491,226	$489,598	$487,970	$486,343	$484,716	$483,089	$488,667	$486,986	$485,306	$483,625	$481,944	$480,264	$5,829,734

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($105,398), 312.46 ($94,929,061) & 315.46 ($220,782)
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5%, 3.3% and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2019 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$15,779	$0	$17,978	$0	$0	($623)	$0	$0	$0	$0	$0	$0	$33,134
	b. Clearings to Plant		15,779	0	32,814	0	0	0	0	0	0	0	0	0	48,593
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$22,605,336	$22,621,115	$22,621,115	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	
3.	Less: Accumulated Depreciation	(9,345,550)	(9,393,067)	(9,440,625)	(9,488,183)	(9,535,830)	(9,583,477)	(9,631,124)	(9,678,771)	(9,726,418)	(9,774,065)	(9,821,712)	(9,869,359)	(9,917,006)	
4.	CWIP - Non-Interest Bearing	15,459	15,459	15,459	623	623	623	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$13,275,246	13,243,507	13,195,949	13,166,369	13,118,722	13,071,075	13,022,805	12,975,158	12,927,511	12,879,864	12,832,217	12,784,570	12,736,923	
6.	Average Net Investment		13,259,377	13,219,728	13,181,159	13,142,546	13,094,899	13,046,940	12,998,982	12,951,335	12,903,688	12,856,041	12,808,394	12,760,747	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$63,438	$63,249	$63,064	$62,879	$62,651	$62,422	$64,600	$64,363	$64,126	$63,889	$63,652	$63,416	$761,749
	b. Debt Component Grossed Up For Taxes (C)		18,943	18,887	18,831	18,776	18,708	18,640	18,815	18,746	18,677	18,608	18,539	18,470	224,640
8.	Investment Expenses														
	a. Depreciation (D)		47,517	47,558	47,558	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	571,456
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		129,898	129,694	129,453	129,302	129,006	128,709	131,062	130,756	130,450	130,144	129,838	129,533	1,557,845
	a. Recoverable Costs Allocated to Energy		129,898	129,694	129,453	129,302	129,006	128,709	131,062	130,756	130,450	130,144	129,838	129,533	1,557,845
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		129,898	129,694	129,453	129,302	129,006	128,709	131,062	130,756	130,450	130,144	129,838	129,533	1,557,845
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$129,898	$129,694	$129,453	$129,302	$129,006	$128,709	$131,062	$130,756	$130,450	$130,144	$129,838	$129,533	$1,557,845

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,855,886), 311.45 ($40,016), 316.40 ($71,401), 315.45 ($594,901), 312.42 ($1,637), and 312.40 ($90,088)
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5%, 2.0%, 4.2%, 3.1%, 3.7%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	1,749,771	1,739,587	1,729,403	1,719,219	1,709,035	1,698,851	1,688,667	1,678,483	1,668,299	1,658,115	1,647,931	1,637,747	1,627,563	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,940,623	4,930,439	4,920,255	4,910,071	4,899,887	4,889,703	4,879,519	4,869,335	4,859,151	4,848,967	4,838,783	4,828,599	4,818,415	
6.	Average Net Investment		4,935,531	4,925,347	4,915,163	4,904,979	4,894,795	4,884,611	4,874,427	4,864,243	4,854,059	4,843,875	4,833,691	4,823,507	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$23,614	$23,565	$23,516	$23,467	$23,419	$23,370	$24,224	$24,173	$24,123	$24,072	$24,021	$23,971	$285,535
	b. Debt Component Grossed Up For Taxes (C)		7,051	7,037	7,022	7,008	6,993	6,978	7,055	7,041	7,026	7,011	6,996	6,982	84,200
8.	Investment Expenses														
	a. Depreciation (D)		10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		40,849	40,786	40,722	40,659	40,596	40,532	41,463	41,398	41,333	41,267	41,201	41,137	491,943
	a. Recoverable Costs Allocated to Energy		40,849	40,786	40,722	40,659	40,596	40,532	41,463	41,398	41,333	41,267	41,201	41,137	491,943
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		40,849	40,786	40,722	40,659	40,596	40,532	41,463	41,398	41,333	41,267	41,201	41,137	491,943
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$40,849	$40,786	$40,722	$40,659	$40,596	$40,532	$41,463	$41,398	$41,333	$41,267	$41,201	$41,137	$491,943

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 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	-	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	
3.	Less: Accumulated Depreciation	(5,814,322)	(5,875,194)	(5,936,066)	(5,996,938)	(6,057,810)	(6,118,682)	(6,179,554)	(6,240,426)	(6,301,298)	(6,362,170)	(6,423,042)	(6,483,914)	(6,544,786)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$13,943,428	13,882,556	13,821,684	13,760,812	13,699,940	13,639,068	13,578,196	13,517,324	13,456,452	13,395,580	13,334,708	13,273,836	13,212,964	
6.	Average Net Investment		13,912,992	13,852,120	13,791,248	13,730,376	13,669,504	13,608,632	13,547,760	13,486,888	13,426,016	13,365,144	13,304,272	13,243,400	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$66,566	$66,274	$65,983	$65,692	$65,401	$65,109	$67,327	$67,024	$66,722	$66,419	$66,117	$65,814	$794,448
	b. Debt Component Grossed Up For Taxes (C)		19,877	19,790	19,703	19,616	19,529	19,442	19,609	19,521	19,433	19,345	19,257	19,169	234,291
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)		147,315	146,936	146,558	146,180	145,802	145,423	147,808	147,417	147,027	146,636	146,246	145,855	1,759,203
	a. Recoverable Costs Allocated to Energy		147,315	146,936	146,558	146,180	145,802	145,423	147,808	147,417	147,027	146,636	146,246	145,855	1,759,203
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		147,315	146,936	146,558	146,180	145,802	145,423	147,808	147,417	147,027	146,636	146,246	145,855	1,759,203
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$147,315	$146,936	$146,558	$146,180	$145,802	$145,423	$147,808	$147,417	$147,027	$146,636	$146,246	$145,855	$1,759,203

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 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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

DOCKET NO. 20200007-EI
ECRC 2019 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(789,498)	(793,922)	(798,346)	(802,770)	(807,194)	(811,618)	(816,042)	(820,466)	(824,890)	(829,314)	(833,738)	(838,162)	(842,586)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$771,975	767,551	763,127	758,703	754,279	749,855	745,431	741,007	736,583	732,159	727,735	723,311	718,887	
6.	Average Net Investment		769,763	765,339	760,915	756,491	752,067	747,643	743,219	738,795	734,371	729,947	725,523	721,099	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,683	$3,662	$3,641	$3,619	$3,598	$3,577	$3,693	$3,672	$3,650	$3,628	$3,606	$3,584	$43,613
	b. Debt Component Grossed Up For Taxes (C)		1,100	1,093	1,087	1,081	1,074	1,068	1,076	1,069	1,063	1,057	1,050	1,044	12,862
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)		9,207	9,179	9,152	9,124	9,096	9,069	9,193	9,165	9,137	9,109	9,080	9,052	109,563
	a. Recoverable Costs Allocated to Energy		9,207	9,179	9,152	9,124	9,096	9,069	9,193	9,165	9,137	9,109	9,080	9,052	109,563
	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)		9,207	9,179	9,152	9,124	9,096	9,069	9,193	9,165	9,137	9,109	9,080	9,052	109,563
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)		$9,207	$9,179	$9,152	$9,124	$9,096	$9,069	$9,193	$9,165	$9,137	$9,109	$9,080	$9,052	$109,563

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(986,198)	(992,595)	(998,992)	(1,005,389)	(1,011,786)	(1,018,183)	(1,024,580)	(1,030,977)	(1,037,374)	(1,043,771)	(1,050,168)	(1,056,565)	(1,062,962)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,572,532	1,566,135	1,559,738	1,553,341	1,546,944	1,540,547	1,534,150	1,527,753	1,521,356	1,514,959	1,508,562	1,502,165	1,495,768	
6.	Average Net Investment		1,569,334	1,562,937	1,556,540	1,550,143	1,543,746	1,537,349	1,530,952	1,524,555	1,518,158	1,511,761	1,505,364	1,498,967	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,508	$7,478	$7,447	$7,417	$7,386	$7,355	$7,608	$7,576	$7,545	$7,513	$7,481	$7,449	$89,763
	b. Debt Component Grossed Up For Taxes (C)		2,242	2,233	2,224	2,215	2,205	2,196	2,216	2,207	2,197	2,188	2,179	2,170	26,472
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)		16,147	16,108	16,068	16,029	15,988	15,948	16,221	16,180	16,139	16,098	16,057	16,016	192,999
	a. Recoverable Costs Allocated to Energy		16,147	16,108	16,068	16,029	15,988	15,948	16,221	16,180	16,139	16,098	16,057	16,016	192,999
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		16,147	16,108	16,068	16,029	15,988	15,948	16,221	16,180	16,139	16,098	16,057	16,016	192,999
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,147	$16,108	$16,068	$16,029	$15,988	$15,948	$16,221	$16,180	$16,139	$16,098	$16,057	$16,016	$192,999

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(731,593)	(737,090)	(742,587)	(748,084)	(753,581)	(759,078)	(764,575)	(770,072)	(775,569)	(781,066)	(786,563)	(792,060)	(797,557)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$917,528	912,031	906,534	901,037	895,540	890,043	884,546	879,049	873,552	868,055	862,558	857,061	851,564	
6.	Average Net Investment		914,780	909,283	903,786	898,289	892,792	887,295	881,798	876,301	870,804	865,307	859,810	854,313	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,377	$4,350	$4,324	$4,298	$4,271	$4,245	$4,382	$4,355	$4,328	$4,300	$4,273	$4,246	$51,749
	b. Debt Component Grossed Up For Taxes (C)		1,307	1,299	1,291	1,283	1,275	1,268	1,276	1,268	1,260	1,252	1,245	1,237	15,261
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)		11,181	11,146	11,112	11,078	11,043	11,010	11,155	11,120	11,085	11,049	11,015	10,980	132,974
	a. Recoverable Costs Allocated to Energy		11,181	11,146	11,112	11,078	11,043	11,010	11,155	11,120	11,085	11,049	11,015	10,980	132,974
	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)		11,181	11,146	11,112	11,078	11,043	11,010	11,155	11,120	11,085	11,049	11,015	10,980	132,974
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)		$11,181	$11,146	$11,112	$11,078	$11,043	$11,010	$11,155	$11,120	$11,085	$11,049	$11,015	$10,980	$132,974

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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 (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(652,844)	(657,721)	(662,598)	(667,475)	(672,352)	(677,229)	(682,106)	(686,983)	(691,860)	(696,737)	(701,614)	(706,491)	(711,368)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$929,043	924,166	919,289	914,412	909,535	904,658	899,781	894,904	890,027	885,150	880,273	875,396	870,519	
6.	Average Net Investment		926,605	921,728	916,851	911,974	907,097	902,220	897,343	892,466	887,589	882,712	877,835	872,958	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,433	$4,410	$4,387	$4,363	$4,340	$4,317	$4,459	$4,435	$4,411	$4,387	$4,362	$4,338	$52,642
	b. Debt Component Grossed Up For Taxes (C)		1,324	1,317	1,310	1,303	1,296	1,289	1,299	1,292	1,285	1,278	1,271	1,264	15,528
8.	Investment Expenses														
	a. Depreciation (D)		4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,634	10,604	10,574	10,543	10,513	10,483	10,635	10,604	10,573	10,542	10,510	10,479	126,694
	a. Recoverable Costs Allocated to Energy		10,634	10,604	10,574	10,543	10,513	10,483	10,635	10,604	10,573	10,542	10,510	10,479	126,694
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,634	10,604	10,574	10,543	10,513	10,483	10,635	10,604	10,573	10,542	10,510	10,479	126,694
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,634	$10,604	$10,574	$10,543	$10,513	$10,483	$10,635	$10,604	$10,573	$10,542	$10,510	$10,479	$126,694

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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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ECRC 2019 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(927,638)	(935,591)	(943,544)	(951,497)	(959,450)	(967,403)	(975,356)	(983,309)	(991,262)	(999,215)	(1,007,168)	(1,015,121)	(1,023,074)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,778,869	1,770,916	1,762,963	1,755,010	1,747,057	1,739,104	1,731,151	1,723,198	1,715,245	1,707,292	1,699,339	1,691,386	1,683,433	
6.	Average Net Investment		1,774,893	1,766,940	1,758,987	1,751,034	1,743,081	1,735,128	1,727,175	1,719,222	1,711,269	1,703,316	1,695,363	1,687,410	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$8,492	$8,454	$8,416	$8,378	$8,340	$8,302	$8,583	$8,544	$8,504	$8,465	$8,425	$8,386	$101,289
	b. Debt Component Grossed Up For Taxes (C)		2,536	2,524	2,513	2,502	2,490	2,479	2,500	2,488	2,477	2,465	2,454	2,442	29,870
8.	Investment Expenses														
	a. Depreciation (D)		7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,981	18,931	18,882	18,833	18,783	18,734	19,036	18,985	18,934	18,883	18,832	18,781	226,595
	a. Recoverable Costs Allocated to Energy		18,981	18,931	18,882	18,833	18,783	18,734	19,036	18,985	18,934	18,883	18,832	18,781	226,595
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		18,981	18,931	18,882	18,833	18,783	18,734	19,036	18,985	18,934	18,883	18,832	18,781	226,595
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,981	$18,931	$18,882	$18,833	$18,783	$18,734	$19,036	$18,985	$18,934	$18,883	$18,832	$18,781	$226,595

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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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ECRC 2019 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	
3.	Less: Accumulated Depreciation	(32,559,630)	(32,868,796)	(33,177,962)	(33,487,128)	(33,796,294)	(34,105,460)	(34,414,626)	(34,723,792)	(35,032,958)	(35,342,124)	(35,651,290)	(35,960,456)	(36,269,622)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$53,159,472	52,850,306	52,541,140	52,231,974	51,922,808	51,613,642	51,304,476	50,995,310	50,686,144	50,376,978	50,067,812	49,758,646	49,449,480	
6.	Average Net Investment		53,004,889	52,695,723	52,386,557	52,077,391	51,768,225	51,459,059	51,149,893	50,840,727	50,531,561	50,222,395	49,913,229	49,604,063	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$253,597	$252,118	$250,639	$249,160	$247,681	$246,202	$254,194	$252,657	$251,121	$249,584	$248,048	$246,512	$3,001,513
	b. Debt Component Grossed Up For Taxes (C)		75,726	75,284	74,843	74,401	73,959	73,518	74,035	73,588	73,140	72,693	72,245	71,798	885,230
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)		638,489	636,568	634,648	632,727	630,806	628,886	637,395	635,411	633,427	631,443	629,459	627,476	7,596,735
	a. Recoverable Costs Allocated to Energy		638,489	636,568	634,648	632,727	630,806	628,886	637,395	635,411	633,427	631,443	629,459	627,476	7,596,735
	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)		638,489	636,568	634,648	632,727	630,806	628,886	637,395	635,411	633,427	631,443	629,459	627,476	7,596,735
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)		$638,489	$636,568	$634,648	$632,727	$630,806	$628,886	$637,395	$635,411	$633,427	$631,443	$629,459	$627,476	$7,596,735

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 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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

DOCKET NO. 20200007-EI
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	
3.	Less: Accumulated Depreciation	(34,526,712)	(34,839,089)	(35,151,466)	(35,463,843)	(35,776,220)	(36,088,597)	(36,400,974)	(36,713,351)	(37,025,728)	(37,338,105)	(37,650,482)	(37,962,859)	(38,275,236)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$62,011,421	61,699,044	61,386,667	61,074,290	60,761,913	60,449,536	60,137,159	59,824,782	59,512,405	59,200,028	58,887,651	58,575,274	58,262,897	
6.	Average Net Investment		61,855,232	61,542,855	61,230,478	60,918,101	60,605,724	60,293,347	59,980,970	59,668,593	59,356,216	59,043,839	58,731,462	58,419,085	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$295,941	$294,447	$292,952	$291,458	$289,963	$288,468	$298,080	$296,528	$294,976	$293,423	$291,871	$290,319	$3,518,426
	b. Debt Component Grossed Up For Taxes (C)		88,370	87,924	87,478	87,031	86,585	86,139	86,817	86,365	85,913	85,461	85,009	84,557	1,037,649
8.	Investment Expenses														
	a. Depreciation (D)		312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	3,748,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		696,688	694,748	692,807	690,866	688,925	686,984	697,274	695,270	693,266	691,261	689,257	687,253	8,304,599
	a. Recoverable Costs Allocated to Energy		696,688	694,748	692,807	690,866	688,925	686,984	697,274	695,270	693,266	691,261	689,257	687,253	8,304,599
	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)		696,688	694,748	692,807	690,866	688,925	686,984	697,274	695,270	693,266	691,261	689,257	687,253	8,304,599
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)		$696,688	$694,748	$692,807	$690,866	$688,925	$686,984	$697,274	$695,270	$693,266	$691,261	$689,257	$687,253	$8,304,599

Notes:

(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($54,456,221), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	
3.	Less: Accumulated Depreciation	(30,963,585)	(31,215,659)	(31,467,733)	(31,719,807)	(31,971,881)	(32,223,955)	(32,476,029)	(32,728,103)	(32,980,177)	(33,232,251)	(33,484,325)	(33,736,399)	(33,988,473)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$50,801,017	50,548,943	50,296,869	50,044,795	49,792,721	49,540,647	49,288,573	49,036,499	48,784,425	48,532,351	48,280,277	48,028,203	47,776,129	
6.	Average Net Investment		50,674,980	50,422,906	50,170,832	49,918,758	49,666,684	49,414,610	49,162,536	48,910,462	48,658,388	48,406,314	48,154,240	47,902,166	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$242,450	$241,244	$240,038	$238,832	$237,626	$236,420	$244,317	$243,065	$241,812	$240,559	$239,307	$238,054	$2,883,724
	b. Debt Component Grossed Up For Taxes (C)		72,397	72,037	71,677	71,317	70,957	70,597	71,159	70,794	70,429	70,064	69,699	69,334	850,461
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)		566,921	565,355	563,789	562,223	560,657	559,091	567,550	565,933	564,315	562,697	561,080	559,462	6,759,073
	a. Recoverable Costs Allocated to Energy		566,921	565,355	563,789	562,223	560,657	559,091	567,550	565,933	564,315	562,697	561,080	559,462	6,759,073
	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)		566,921	565,355	563,789	562,223	560,657	559,091	567,550	565,933	564,315	562,697	561,080	559,462	6,759,073
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)		$566,921	$565,355	$563,789	$562,223	$560,657	$559,091	$567,550	$565,933	$564,315	$562,697	$561,080	$559,462	$6,759,073

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 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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 (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$4,885	$4,712	$16,667	$931	$301	$0	$0	$0	$0	$0	$0	$0	$27,496
	b. Clearings to Plant		4,885	4,712	16,667	931	301	0	0	0	0	0	0	0	27,496
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$66,787,365	$66,792,250	$66,796,962	$66,813,629	$66,814,559	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	
3.	Less: Accumulated Depreciation	(24,766,293)	(24,958,673)	(25,151,069)	(25,343,480)	(25,535,944)	(25,728,411)	(25,920,879)	(26,113,347)	(26,305,815)	(26,498,283)	(26,690,751)	(26,883,219)	(27,075,687)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$42,021,072	41,833,577	41,645,893	41,470,149	41,278,615	41,086,450	40,893,982	40,701,514	40,509,046	40,316,578	40,124,110	39,931,642	39,739,174	
6.	Average Net Investment		41,927,324	41,739,735	41,558,021	41,374,382	41,182,533	40,990,216	40,797,748	40,605,280	40,412,812	40,220,344	40,027,876	39,835,408	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$200,598	$199,700	$198,831	$197,952	$197,034	$196,114	$202,748	$201,791	$200,835	$199,878	$198,922	$197,965	$2,392,368
	b. Debt Component Grossed Up For Taxes (C)		59,900	59,632	59,372	59,110	58,836	58,561	59,051	58,773	58,494	58,216	57,937	57,658	705,540
8.	Investment Expenses														
	a. Depreciation (D)		192,380	192,396	192,411	192,464	192,467	192,468	192,468	192,468	192,468	192,468	192,468	192,468	2,309,394
	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)		452,878	451,728	450,614	449,526	448,337	447,143	454,267	453,032	451,797	450,562	449,327	448,091	5,407,302
	a. Recoverable Costs Allocated to Energy		452,878	451,728	450,614	449,526	448,337	447,143	454,267	453,032	451,797	450,562	449,327	448,091	5,407,302
	b. Recoverable Costs Allocated to Demand		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)		452,878	451,728	450,614	449,526	448,337	447,143	454,267	453,032	451,797	450,562	449,327	448,091	5,407,302
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)		$452,878	$451,728	$450,614	$449,526	$448,337	$447,143	$454,267	$453,032	$451,797	$450,562	$449,327	$448,091	$5,407,302

Notes:
(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($38,069,546), 315.54 ($10,642,027), 316.54 ($687,934), and 315.40 ($558,103)
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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 (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$25	$5,335	$24,907	$3,706	$1,657	$1,129	$2,804	$0	$0	$0	$0	$0	$39,562
	b. Clearings to Plant		91,562	5,335	24,907	3,706	1,657	1,129	2,804	0	0	0	0	0	131,099
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$24,336,707	$24,428,269	$24,433,604	$24,458,510	$24,462,216	$24,463,873	$24,465,002	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	
3.	Less: Accumulated Depreciation	(5,216,370)	(5,267,679)	(5,319,178)	(5,370,689)	(5,422,251)	(5,473,821)	(5,525,395)	(5,576,971)	(5,628,553)	(5,680,135)	(5,731,717)	(5,783,299)	(5,834,881)	
4.	CWIP - Non-Interest Bearing	91,537	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$19,211,874	19,160,590	19,114,426	19,087,821	19,039,965	18,990,052	18,939,607	18,890,835	18,839,253	18,787,671	18,736,089	18,684,507	18,632,925	
6.	Average Net Investment		19,186,232	19,137,508	19,101,123	19,063,893	19,015,008	18,964,829	18,915,221	18,865,044	18,813,462	18,761,880	18,710,298	18,658,716	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$91,795	$91,562	$91,388	$91,210	$90,976	$90,736	$94,001	$93,751	$93,495	$93,239	$92,982	$92,726	$1,107,861
	b. Debt Component Grossed Up For Taxes (C)		27,411	27,341	27,289	27,236	27,166	27,094	27,378	27,306	27,231	27,156	27,082	27,007	326,697
8.	Investment Expenses														
	a. Depreciation (D)		51,309	51,499	51,511	51,562	51,570	51,574	51,576	51,582	51,582	51,582	51,582	51,582	618,511
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		170,515	170,402	170,188	170,008	169,712	169,404	172,955	172,639	172,308	171,977	171,646	171,315	2,053,069
	a. Recoverable Costs Allocated to Energy		170,515	170,402	170,188	170,008	169,712	169,404	172,955	172,639	172,308	171,977	171,646	171,315	2,053,069
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		170,515	170,402	170,188	170,008	169,712	169,404	172,955	172,639	172,308	171,977	171,646	171,315	2,053,069
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$170,515	$170,402	$170,188	$170,008	$169,712	$169,404	$172,955	$172,639	$172,308	$171,977	$171,646	$171,315	$2,053,069

Notes:

(A) Applicable depreciable base for Big Bend; account 312.45 ($23,011,597) and 312.44 ($1,456,209).
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,614	$0	$0	$13,614
	b. Clearings to Plant		13,534	0	0	0	0	0	0	0	0	0	0	0	13,534
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	8,607,879	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	8,621,413	
3.	Less: Accumulated Depreciation	(1,420,316)	(1,442,451)	(1,464,747)	(1,487,043)	(1,509,339)	(1,531,635)	(1,553,931)	(1,576,227)	(1,598,523)	(1,620,819)	(1,643,115)	(1,665,411)	(1,687,707)	
4.	CWIP - Non-Interest Bearing	13,534	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	13,614	13,614	13,614	
5.	Net Investment (Lines 2 + 3 + 4)	$7,201,097	7,178,962	7,156,666	7,134,370	7,112,074	7,089,778	7,067,482	7,045,186	7,022,890	7,000,594	6,991,912	6,969,616	6,947,321	
6.	Average Net Investment		7,190,029	7,167,814	7,145,518	7,123,222	7,100,926	7,078,630	7,056,334	7,034,038	7,011,742	6,996,253	6,980,764	6,958,469	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$34,400	$34,294	$34,187	$34,080	$33,974	$33,867	$35,067	$34,956	$34,845	$34,768	$34,691	$34,581	$413,710
	b. Debt Component Grossed Up For Taxes (C)		10,272	10,240	10,209	10,177	10,145	10,113	10,213	10,181	10,149	10,126	10,104	10,072	122,001
8.	Investment Expenses														
	a. Depreciation (D)		22,135	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	267,391
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,807	66,830	66,692	66,553	66,415	66,276	67,576	67,433	67,290	67,190	67,091	66,949	803,102
	a. Recoverable Costs Allocated to Energy		66,807	66,830	66,692	66,553	66,415	66,276	67,576	67,433	67,290	67,190	67,091	66,949	803,102
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		66,807	66,830	66,692	66,553	66,415	66,276	67,576	67,433	67,290	67,190	67,091	66,949	803,102
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$66,807	$66,830	$66,692	$66,553	$66,415	$66,276	$67,576	$67,433	$67,290	$67,190	$67,091	$66,949	$803,102

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.44 ($3,427,481), 341.80($26,150), 315.40 ($1,226,949), 315.41 ($138,853), 315.42 ($138,853), 312.45 ($2,053,017), 312.46 ($1,242,315), 315.44 ($16,035), 315.45 ($40,217) and 315.46 ($50,784), 311.40 ($13,216), 345.81 ($2,232), 312.54 ($210,295) and 395.00 ($35,018)

(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)

(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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 (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	0	93	0	0	0	0	0	0	0	93
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	(34,333.03)	(34,315)	(34,315)	(34,315)	(34,303)	(34,302)	(34,302)	(34,288)	(34,288)	(34,288)	(34,280)	(34,280)	(34,280)	
3.	Total Working Capital Balance	($34,333)	(34,315)	(34,315)	(34,315)	(34,303)	(34,302)	(34,302)	(34,288)	(34,288)	(34,288)	(34,280)	(34,280)	(34,280)	
4.	Average Net Working Capital Balance		($34,324)	($34,315)	($34,315)	($34,309)	($34,303)	($34,302)	($34,295)	($34,288)	($34,288)	($34,284)	($34,280)	($34,280)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($164)	($164)	($164)	($164)	($164)	($164)	($170)	($170)	($170)	($170)	($170)	($170)	($2,004)
	b. Debt Component Grossed Up For Taxes (B)		(49)	(49)	(49)	(49)	(49)	(49)	(50)	(50)	(50)	(50)	(50)	(50)	(594)
6.	Total Return Component		(213)	(213)	(213)	(213)	(213)	(213)	(220)	(220)	(220)	(220)	(220)	(220)	(2,598)
7.	Expenses:														
	a. Gains		0	0	0	0	(93)	0	0	0	0	0	0	0	(93)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		8	12	5	(6)	8	7	(5)	13	14	(3)	26	17	97
8.	Net Expenses (D)		8	12	5	(6)	(85)	7	(5)	13	14	(3)	26	17	4
9.	Total System Recoverable Expenses (Lines 6 + 8)		(205)	(201)	(208)	(219)	(298)	(206)	(225)	(207)	(206)	(223)	(194)	(203)	(2,594)
	a. Recoverable Costs Allocated to Energy		(205)	(201)	(208)	(219)	(298)	(206)	(225)	(207)	(206)	(223)	(194)	(203)	(2,594)
	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)		(205)	(201)	(208)	(219)	(298)	(206)	(225)	(207)	(206)	(223)	(194)	(203)	(2,595)
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)		($205)	($201)	($208)	($219)	($298)	($206)	($225)	($207)	($206)	($223)	($194)	($203)	($2,595)

Notes:
(A) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(C) Line 6 is reported on Schedule 7A.
(D) Line 8 is reported on Schedule 5A.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility (East 40)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
	b. Clearings to Plant		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	
3.	Less: Accumulated Depreciation	(2,532,327)	(2,584,206)	(2,636,085)	(2,687,964)	(2,739,843)	(2,791,722)	(2,843,601)	(2,895,480)	(2,947,359)	(2,999,238)	(3,051,117)	(3,102,996)	(3,154,875)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$18,935,032	18,883,153	18,831,274	18,779,395	18,727,516	18,675,637	18,623,758	18,571,879	18,520,000	18,468,121	18,416,242	18,364,363	18,312,484	
6.	Average Net Investment		18,909,093	18,857,214	18,805,335	18,753,456	18,701,577	18,649,698	18,597,819	18,545,940	18,494,061	18,442,182	18,390,303	18,338,424	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$90,469	$90,221	$89,973	$89,724	$89,476	$89,228	$92,423	$92,166	$91,908	$91,650	$91,392	$91,134	$1,089,764
	b. Debt Component Grossed Up For Taxes (C)		27,015	26,941	26,866	26,792	26,718	26,644	26,919	26,844	26,769	26,694	26,618	26,543	321,363
8.	Investment Expenses														
	a. Depreciation (D)		51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	622,548
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		169,363	169,041	168,718	168,395	168,073	167,751	171,221	170,889	170,556	170,223	169,889	169,556	2,033,675
	a. Recoverable Costs Allocated to Energy		169,363	169,041	168,718	168,395	168,073	167,751	171,221	170,889	170,556	170,223	169,889	169,556	2,033,675
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		169,363	169,041	168,718	168,395	168,073	167,751	171,221	170,889	170,556	170,223	169,889	169,556	2,033,675
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$169,363	$169,041	$168,718	$168,395	$168,073	$167,751	$171,221	$170,889	$170,556	$170,223	$169,889	$169,556	$2,033,675

Notes:

(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% 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 (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend CCR Rule - Phase I
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$21,197	$102,544	($20,835)	$99,904	$112,597	($46,550)	$25,148	($15,861)	$508	$8,307	($2,388)	$3,766	$288,337
	b. Clearings to Plant		0	0	0	0	0	0	0	0	261,568	0	0	0	261,568
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	668,735	668,735	668,735	668,735	668,735	668,735	668,735	668,735	668,735	930,303	930,303	930,303	930,303	
3.	Less: Accumulated Depreciation	(28,161)	(29,833)	(31,505)	(33,177)	(34,849)	(36,521)	(38,193)	(39,865)	(41,537)	(43,209)	(45,513)	(47,817)	(50,121)	
4.	CWIP - Non-Interest Bearing	264,377	285,574	388,118	367,283	467,186	579,783	533,234	558,382	542,521	281,461	289,768	287,379	291,146	
5.	Net Investment (Lines 2 + 3 + 4)	904,951	924,475	1,025,348	1,002,840	1,101,072	1,211,997	1,163,775	1,187,252	1,169,719	1,168,555	1,174,558	1,169,865	1,171,328	
6.	Average Net Investment		914,713	974,912	1,014,094	1,051,956	1,156,534	1,187,886	1,175,513	1,178,485	1,169,137	1,171,556	1,172,212	1,170,597	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,376	$4,664	$4,852	$5,033	$5,533	$5,683	$5,842	$5,857	$5,810	$5,822	$5,825	$5,817	$65,114
	b. Debt Component Grossed Up For Taxes (C)		1,307	1,393	1,449	1,503	1,652	1,697	1,701	1,706	1,692	1,696	1,697	1,694	19,187
8.	Investment Expenses														
	a. Depreciation (D)		1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	2,304	2,304	2,304	21,960
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,355	7,729	7,973	8,208	8,857	9,052	9,215	9,235	9,174	9,822	9,826	9,815	106,261
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,355	7,729	7,973	8,208	8,857	9,052	9,215	9,235	9,174	9,822	9,826	9,815	106,261
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		7,355	7,729	7,973	8,208	8,857	9,052	9,215	9,235	9,174	9,822	9,826	9,815	106,261
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,355	$7,729	$7,973	$8,208	$8,857	$9,052	$9,215	$9,235	$9,174	$9,822	$9,826	$9,815	$106,261

Notes:

(A) Applicable depreciable base for Big Bend ; accounts 311.40 ($261,568) and 312.44 ($668,735)
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9% and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend CCR Rule - Phase II
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$29,606	$140,630	($853)	$13,342	$16,693	$7,097	$8,833	$5,099	$20,312	$6,127	$17,224	$75,122	$339,231
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	-	-	-	-	-	-	-	-	-	-	-	-	-	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	342,600	372,206	512,836	511,983	525,325	542,018	549,114	557,948	563,047	583,359	589,485	606,709	681,830	
5.	Net Investment (Lines 2 + 3 + 4)	$342,600	372,206	512,836	511,983	525,325	542,018	549,114	557,948	563,047	583,359	589,485	606,709	681,830	
6.	Average Net Investment		357,403	442,521	512,409	518,654	533,671	545,566	553,531	560,497	573,203	586,422	598,097	644,270	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,710	$2,117	$2,452	$2,481	$2,553	$2,610	$2,751	$2,785	$2,849	$2,914	$2,972	$3,202	$31,396
	b. Debt Component Grossed Up For Taxes (C)		511	632	732	741	762	779	801	811	830	849	866	933	9,247
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)		2,221	2,749	3,184	3,222	3,315	3,389	3,552	3,596	3,679	3,763	3,838	4,135	40,643
	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		2,221	2,749	3,184	3,222	3,315	3,389	3,552	3,596	3,679	3,763	3,838	4,135	40,643
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)		2,221	2,749	3,184	3,222	3,315	3,389	3,552	3,596	3,679	3,763	3,838	4,135	40,643
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$2,221	$2,749	$3,184	$3,222	$3,315	$3,389	$3,552	$3,596	$3,679	$3,763	$3,838	$4,135	$40,643

Notes:

(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

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

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$44,708	$18,003	$3,833	$4,236	$20,673	$2,614	$1,959	$4,697	$668	$2,709	$1,047	$17,451	$122,598
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	-	-	-	-	-	-	-	-	-	-	-	-	-	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	16,996	61,704	79,706	83,540	87,776	108,449	111,063	113,022	117,720	118,387	121,096	122,143	139,594	
5.	Net Investment (Lines 2 + 3 + 4)	$16,996	61,704	79,706	83,540	87,776	108,449	111,063	113,022	117,720	118,387	121,096	122,143	139,594	
6.	Average Net Investment		39,350	70,705	81,623	85,658	98,112	109,756	112,043	115,371	118,053	119,741	121,619	130,869	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$188	$338	$391	$410	$469	$525	$557	$573	$587	$595	$604	$650	$5,887
	b. Debt Component Grossed Up For Taxes (C)		56	101	117	122	140	157	162	167	171	173	176	189	1,731
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)		244	439	508	532	609	682	719	740	758	768	780	839	7,618
	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		244	439	508	532	609	682	719	740	758	768	780	839	7,618
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)		244	439	508	532	609	682	719	740	758	768	780	839	7,618
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$244	$439	$508	$532	$609	$682	$719	$740	$758	$768	$780	$839	$7,618

Notes:
(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Sec. 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$1,692	$1,872	$3,758	$5,009	$10,982	$26,409	$1,711	$3,567	$4,601	$59,601
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	1,692	3,564	7,323	12,332	23,314	49,723	51,434	55,000	59,601	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	1,692	3,564	7,323	12,332	23,314	49,723	51,434	55,000	59,601	
6.	Average Net Investment		0	0	0	846	2,628	5,443	9,827	17,823	36,518	50,578	53,217	57,301	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$4	$13	$26	$49	$89	$181	$251	$264	$285	$1,162
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	1	4	8	14	26	53	73	77	83	339
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	5	17	34	63	115	234	324	341	368	1,501
	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	5	17	34	63	115	234	324	341	368	1,501
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	5	17	34	63	115	234	324	341	368	1,501
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$5	$17	$34	$63	$115	$234	$324	$341	$368	$1,501

Notes:

(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 5.7413% x 1/12 (Jan-Jun) and Line 6 x 5.9635% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7369% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2019 FINAL TRUE-UP
EXHIBIT MAS-1, DOC. NO. 8, PAGE 29 OF 29

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2019 to June 2019

Form 42 - 9A
Page 1 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	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,367,502	Equity - Common	54.00%
Total	$ 4,086,721	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0289% * 46.00%	0.0133%
Equity = .0289% * 54.00%	0.0156%
Weighted Cost	0.0289%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3067%
Deferred ITC - Weighted Cost	0.0156%
	4.3223%
Times Tax Multiplier	1.32830
Total Equity Component	5.7413%

Total Debt Cost Rate:

Long Term Debt	1.5652%
Short Term Debt	0.0945%
Customer Deposits	0.0414%
Deferred ITC - Weighted Cost	0.0133%
Total Debt Component	1.7144%
	7.4557%

Notes:

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
July 2019 to December 2019

Form 42 - 9A
Page 2 of 2

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base **Actual May 2019** ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,897,597	31.57%	4.89%	1.5435%
Short Term Debt	211,895	3.52%	2.97%	0.1047%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	94,966	1.58%	2.38%	0.0376%
Common Equity	2,598,065	43.22%	10.25%	4.4297%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,125,550	18.72%	0.00%	0.0000%
Deferred ITC - Weighted Cost	83,633	1.39%	7.98%	0.1110%
Total	$ 6,011,707	100.00%		6.23%

ITC split between Debt and Equity:

Long Term Debt	$ 1,897,597	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,598,065	Equity - Common	54.00%
Total	$ 4,495,662	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	0.0599%
Weighted Cost	0.1110%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	0.0599%
	4.4896%
Times Tax Multiplier	1.32830
Total Equity Component	5.9635%

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	0.0511%
Total Debt Component	1.7369%
	7.7004%

Notes:

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

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200007-EI
EXHIBIT NO. MAS-2
FILED: 07/31/2020

EXHIBIT TO THE TESTIMONY OF M. ASHLEY SIZEMORE

TAMPA ELECTRIC'S ENVIRONMENTAL COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP

JANUARY 2020 THROUGH DECEMBER 2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 33
PARTY: MAS-2
DESCRIPTION: Environmental Cost Recovery Commission Forms 42-1E through 42-9E for the Period January 2020 through...

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200007-EI
EXHIBIT NO. MAS-2
FILED: 07/31/2020

INDEX

TAMPA ELECTRIC COMPANY

ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL/ESTIMATED TRUE-UP AMOUNT

FOR THE PERIOD

JANUARY 2020 THROUGH DECEMBER 2020

FORMS 42-1E THROUGH 42-9E

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Tampa Electric Company Form 42 - 1E

Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020
(in Dollars)

Line	Period Amount
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($7,885,264)
2. Interest Provision (Form 42-2E, Line 6)	44,088
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 2021 to December 2021 (Lines 1 + 2 + 3)	($7,841,176)

DOCKET NO. 20200007-EI
ECRC 2020 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. MAS-2, DOCUMENT NO. 1, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

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)	$3,526,547	$3,344,653	$3,299,802	$3,727,610	$3,712,808	$4,312,993	$4,651,384	$4,705,883	$4,756,792	$4,375,650	$3,655,630	$3,478,978	$47,548,730
2. True-Up Provision	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,054	542,055	6,504,649
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	4,068,601	3,886,707	3,841,856	4,269,664	4,254,862	4,855,047	5,193,438	5,247,937	5,298,846	4,917,704	4,197,684	4,021,033	54,053,379
4. Jurisdictional ECRC Costs													
a. O & M Activities (Form 42-5E, Line 9)	738,601	332,017	1,464,995	2,638,880	1,012,431	2,176,969	1,539,697	1,536,705	1,540,705	1,539,697	1,537,705	1,537,705	17,596,107
b. Capital Investment Projects (Form 42-7E, Line 9)	3,725,028	3,714,545	3,704,392	3,694,361	3,684,230	3,674,442	3,692,699	3,688,884	3,689,789	3,691,528	3,691,703	3,690,935	44,342,536
c. Total Jurisdictional ECRC Costs	4,463,629	4,046,562	5,169,387	6,333,241	4,696,661	5,851,411	5,232,396	5,225,589	5,230,494	5,231,225	5,229,408	5,228,640	61,938,643
5. Over/(Under) Recovery (Line 3 - Line 4c)	(395,028)	(159,855)	(1,327,531)	(2,063,577)	(441,799)	(996,364)	(38,958)	22,348	68,352	(313,521)	(1,031,724)	(1,207,607)	(7,885,264)
6. Interest Provision (Form 42-3E, Line 10)	14,034	12,261	12,474	5,434	236	214	322	339	180	(32)	(421)	(953)	44,088
7. Beginning Balance True-Up & Interest Provision	6,504,649	5,581,601	4,891,953	3,034,842	434,645	(548,972)	(2,087,176)	(2,667,866)	(3,187,233)	(3,660,755)	(4,516,362)	(6,090,561)	6,504,649
a. Deferred True-Up from January to December 2019 (Order No. PSC-2019-0500-FOF-EI)	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915	3,987,915
8. True-Up Collected/(Refunded) (see Line 2)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,054)	(542,055)	(6,504,649)
9. End of Period Total True-Up (Lines 5+6+7+7a+8)	9,569,516	8,879,868	7,022,757	4,422,560	3,438,943	1,900,739	1,320,049	800,682	327,160	(528,447)	(2,102,646)	(3,853,261)	(3,853,261)
10. Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11. End of Period Total True-Up (Lines 9 + 10)	$9,569,516	$8,879,868	$7,022,757	$4,422,560	$3,438,943	$1,900,739	$1,320,049	$800,682	$327,160	($528,447)	($2,102,646)	($3,853,261)	($3,853,261)

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

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)	$10,492,564	$9,569,516	$8,879,868	$7,022,757	$4,422,560	$3,438,943	$1,900,739	$1,320,049	$800,682	$327,160	($528,447)	($2,102,646)	
2.	Ending True-Up Amount Before Interest	9,555,482	8,867,607	7,010,283	4,417,126	3,438,707	1,900,525	1,319,727	800,343	326,980	(528,415)	(2,102,225)	(3,852,308)	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	20,048,046	18,437,123	15,890,151	11,439,883	7,861,267	5,339,468	3,220,466	2,120,392	1,127,662	(201,255)	(2,630,672)	(5,954,954)	
4.	Average True-Up Amount (Line 3 x 1/2)	10,024,023	9,218,562	7,945,076	5,719,942	3,930,634	2,669,734	1,610,233	1,060,196	563,831	(100,628)	(1,315,336)	(2,977,477)	
5.	Interest Rate (First Day of Reporting Business Month)	1.71%	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.38%	0.38%	0.38%	0.38%	0.38%	
6.	Interest Rate (First Day of Subsequent Business Month)	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.35%	3.20%	3.77%	2.27%	0.14%	0.19%	0.49%	0.76%	0.76%	0.76%	0.76%	0.76%	
8.	Average Interest Rate (Line 7 x 1/2)	1.675%	1.600%	1.885%	1.135%	0.070%	0.095%	0.245%	0.380%	0.380%	0.380%	0.380%	0.380%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.140%	0.133%	0.157%	0.095%	0.006%	0.008%	0.020%	0.032%	0.032%	0.032%	0.032%	0.032%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$14,034	$12,261	$12,474	$5,434	$236	$214	$322	$339	$180	($32)	($421)	($953)	$44,088

DOCKET NO. 20200007-EI
ECRC 2020 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. MAS-2, DOCUMENT NO. 3, PAGE 1 OF 1

Tampa Electric Company Form 42 - 4E

Environmental Cost Recovery Clause

Calculation of the Current Period Actual / Estimated Amount

January 2020 to December 2020

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	$280,339	$390,754	($110,415)	-28.3%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	(18)	71	(89)	-125.6%
	d. Big Bend Units 1 & 2 FGD	138,950	250,146	(111,195)	-44.5%
	e. Big Bend PM Minimization and Monitoring	301,141	398,500	(97,359)	-24.4%
	f. Big Bend NO_x Emissions Reduction	6,006	12,000	(5,994)	-50.0%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	0	0	0	0.0%
	i. Polk NO_x Emissions Reduction	0	0	0	0.0%
	j. Bayside SCR and Ammonia	93,185	119,000	(25,815)	-21.7%
	k. Big Bend Unit 4 SOFA	0	0	0	0.0%
	l. Big Bend Unit 1 Pre-SCR	5,400	10,800	(5,400)	-50.0%
	m. Big Bend Unit 2 Pre-SCR	6,175	10,800	(4,625)	-42.8%
	n. Big Bend Unit 3 Pre-SCR	6,815	12,000	(5,185)	-43.2%
	o. Clean Water Act Section 316(b) Phase II Study	28,110	40,000	(11,891)	-29.7%
	p. Arsenic Groundwater Standard Program	15,858	0	15,858	0.0%
	q. Big Bend Unit 1 SCR	87,529	164,668	(77,139)	-46.8%
	r. Big Bend Unit 2 SCR	252,179	329,616	(77,437)	-23.5%
	s. Big Bend Unit 3 SCR	457,095	716,027	(258,932)	-36.2%
	t. Big Bend Unit 4 SCR	727,138	968,634	(241,496)	-24.9%
	u. Mercury Air Toxics Standards	1,873	27,000	(25,127)	-93.1%
	v. Greenhouse Gas Reduction Program	93,149	93,150	0	0.0%
	w. Big Bend Gypsum Storage Facility	796,177	947,064	(150,887)	-15.9%
	x. Big Bend CCR Rule - Phase I	6,381	0	6,381	0.0%
	y. Big Bend ELG Compliance	515	0	515	0.0%
	z. Big Bend CCR Rule - Phase II	14,257,611	4,916,092	9,341,519	190.0%
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0.0%
2.	Total Investment Projects - Recoverable Costs	$17,596,108	$9,440,822	$8,155,287	86.4%
3.	Recoverable Costs Allocated to Energy	$17,517,640	$9,366,322	$8,151,320	87.0%
4.	Recoverable Costs Allocated to Demand	$78,468	$74,500	$3,967	5.3%

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-2019-0500-FOF-EI.

Column (3) = Column (1) - Column (2)

Column (4) = Column (3) / Column (2)

Tampa Electric Company Form 42 - 5E

Environmental Cost Recovery Clause

Calculation of the Current Period Actual / Estimated Amount

January 2020 to December 2020

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	$11,352	$9,360	$20,751	$6,779	$30,045	$15,556	$31,083	$31,083	$31,083	$31,083	$31,083	$31,083	$280,339		$280,339
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	2	5	4	(39)	0	2	(4)	4	4	(4)	4	4	(18)		(18)
	d. Big Bend Units 1 & 2 FGD	3,833	665	1,428	5,488	2,279	184	20,845	20,845	20,845	20,845	20,845	20,845	138,950		138,950
	e. Big Bend PM Minimization and Monitoring	15,123	2,276	509	24,542	18,776	40,666	33,208	33,208	33,208	33,208	33,208	33,208	301,141		301,141
	f. Big Bend NO_x Emissions Reduction	6	0	0	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	6,006		6,006
	g. NPDES Annual Surveillance Fees	46,000	(11,500)	0	0	0	0	0	0	0	0	0	0	34,500	$34,500	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	i. Polk NO_x Emissions Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	j. Bayside SCR and Ammonia	8,637	11,613	8,680	0	0	3,255	12,000	12,000	11,000	10,000	8,000	8,000	93,185		93,185
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	900	900	900	900	900	900	5,400		5,400
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	775	900	900	900	900	900	900	6,175		6,175
	n. Big Bend Unit 3 Pre-SCR	0	815	0	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	6,815		6,815
	o. Clean Water Act Section 316(b) Phase II Study	0	(498)	0	0	2,219	3,389	3,000	0	5,000	5,000	5,000	5,000	28,110	28,110	
	p. Arsenic Groundwater Standard Program	0	2,014	2,297	453	17,197	(12,102)	1,000	1,000	1,000	1,000	1,000	1,000	15,858	15,858	
	q. Big Bend Unit 1 SCR	1,917	6,955	162	5,389	2,130	0	6,692	10,531	14,151	15,687	14,481	9,434	87,529		87,529
	r. Big Bend Unit 2 SCR	26,759	646	5,406	176	9,673	2,373	32,349	26,315	31,252	37,834	54,618	24,779	252,179		252,179
	s. Big Bend Unit 3 SCR	44,130	45,008	32,897	16,070	18,659	8,296	48,471	48,691	48,910	64,378	41,999	39,586	457,095		457,095
	t. Big Bend Unit 4 SCR	47,684	102,104	16,560	9,786	10,017	21,672	94,067	96,042	87,266	63,680	70,481	107,780	727,138		727,138
	u. Mercury Air Toxics Standards	0	0	0	1,621	252	0	0	0	0	0	0	0	1,873		1,873
	v. Greenhouse Gas Reduction Program	0	0	0	93,149	0	0	0	0	0	0	0	0	93,149		93,149
	w. Big Bend Gypsum Storage Facility (East 40)	186,918	61,140	40,791	9,740	4,698	19,357	78,922	78,922	78,922	78,922	78,922	78,922	796,177		796,177
	x. Big Bend CCR Rule - Phase I	2,988	3,393	0	0	0	0	0	0	0	0	0	0	6,381		6,381
	y. Big Bend ELG Compliance	0	0	515	0	0	0	0	0	0	0	0	0	515		515
	z. Big Bend CCR Rule - Phase II	343,254	98,022	1,334,995	2,465,726	896,487	2,073,546	1,174,264	1,174,264	1,174,264	1,174,264	1,174,264	1,174,264	14,257,611		14,257,611
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	738,601	332,017	1,464,995	2,638,880	1,012,431	2,176,969	1,539,697	1,536,705	1,540,705	1,539,697	1,537,705	1,537,705	17,596,108	$78,468	$17,517,640
3.	Recoverable Costs Allocated to Energy	692,601	342,001	1,462,698	2,638,427	993,016	2,185,682	1,535,697	1,535,705	1,534,705	1,533,697	1,531,705	1,531,705	17,517,640		
4.	Recoverable Costs Allocated to Demand	46,000	(9,984)	2,297	453	19,415	(8,713)	4,000	1,000	6,000	6,000	6,000	6,000	78,468		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (A)	692,601	342,001	1,462,698	2,638,427	993,016	2,185,682	1,535,697	1,535,705	1,534,705	1,533,697	1,531,705	1,531,705	17,517,639		
8.	Jurisdictional Demand Recoverable Costs (B)	46,000	(9,984)	2,297	453	19,415	(8,713)	4,000	1,000	6,000	6,000	6,000	6,000	78,468		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$738,601	$332,017	$1,464,995	$2,638,880	$1,012,431	$2,176,969	$1,539,697	$1,536,705	1,540,705	1,539,697	$1,537,705	$1,537,705	$17,596,107		

Notes:

(A) Line 3 x Line 5

(B) Line 4 x Line 6

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Tampa Electric Company Form 42 - 6E

Environmental Cost Recovery Clause

Calculation of the Current Period Actual / Estimated Amount

January 2020 to December 2020

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	$924,091	$925,246	($1,155)	-0.1%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	221,125	221,202	(77)	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	47,462	47,504	(42)	-0.1%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	68,615	68,637	(22)	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	112,855	112,892	(37)	0.0%
	f. Big Bend Unit 1 Classifier Replacement	73,018	73,061	(43)	-0.1%
	g. Big Bend Unit 2 Classifier Replacement	53,081	53,118	(37)	-0.1%
	h. Big Bend Section 114 Mercury Testing Platform	8,161	8,169	(8)	-0.1%
	i. Big Bend Units 1 & 2 FGD	5,648,115	5,653,336	(5,221)	-0.1%
	j. Big Bend FGD Optimization and Utilization	1,536,807	1,538,736	(1,929)	-0.1%
	k. Big Bend NO_x Emissions Reduction	490,945	491,669	(724)	-0.1%
	l. Big Bend PM Minimization and Monitoring	1,726,237	1,728,246	(2,009)	-0.1%
	m. Polk NO_x Emissions Reduction	106,750	106,858	(108)	-0.1%
	n. Big Bend Unit 4 SOFA	189,720	189,948	(228)	-0.1%
	o. Big Bend Unit 1 Pre-SCR	129,410	129,539	(129)	-0.1%
	p. Big Bend Unit 2 Pre-SCR	123,724	123,858	(134)	-0.1%
	q. Big Bend Unit 3 Pre-SCR	222,214	222,468	(254)	-0.1%
	r. Big Bend Unit 1 SCR	7,398,711	7,406,274	(7,563)	-0.1%
	s. Big Bend Unit 2 SCR	8,118,899	8,127,778	(8,879)	-0.1%
	t. Big Bend Unit 3 SCR	6,610,540	6,617,819	(7,279)	-0.1%
	u. Big Bend Unit 4 SCR	5,300,112	5,306,154	(6,042)	-0.1%
	v. Big Bend FGD System Reliability	2,039,210	2,041,735	(2,525)	-0.1%
	w. Mercury Air Toxics Standards	795,655	801,028	(5,373)	-0.7%
	x. SO_2 Emissions Allowances	(2,658)	(2,664)	6	-0.2%
	y. Big Bend Gypsum Storage Facility	2,017,798	2,020,559	(2,761)	-0.1%
	z. Big Bend CCR Rule - Phase I	162,574	185,453	(22,879)	-12.3%
	aa. Big Bend CCR Rule - Phase II	108,456	59,446	49,010	82.4%
	ab. Big Bend ELG Compliance	79,304	145,834	(66,530)	-45.6%
	ac. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	31,605	119,004	(87,399)	-73.4%
2.	Total Investment Projects - Recoverable Costs	$44,342,536	$44,522,907	($180,371)	-0.4%
3.	Recoverable Costs Allocated to Energy	$43,779,127	$43,831,641	($52,514)	-0.1%
4.	Recoverable Costs Allocated to Demand	$563,409	$691,266	($127,857)	-18.5%

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-2019-0500-FOF-EI.

Column (3) = Column (1) - Column (2)

Column (4) = Column (3) / Column (2)

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

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	1	$77,713	$77,527	$77,343	$77,158	$76,972	$76,787	$77,234	$77,046	$76,859	$76,671	$76,484	$76,297	$924,091		$924,091
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	18,984	18,880	18,776	18,673	18,570	18,465	18,392	18,287	18,182	18,077	17,972	17,867	221,125		221,125
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	4,026	4,012	3,996	3,982	3,967	3,952	3,959	3,943	3,929	3,913	3,899	3,884	47,462		47,462
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4	5,895	5,863	5,829	5,797	5,764	5,731	5,706	5,672	5,640	5,606	5,572	5,540	68,615	$68,615	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	5	9,697	9,642	9,588	9,534	9,481	9,427	9,384	9,330	9,275	9,221	9,166	9,110	112,855	112,855	
	f.	Big Bend Unit 1 Classifier Replacement	6	6,229	6,201	6,173	6,144	6,117	6,089	6,082	6,054	6,025	5,997	5,968	5,939	73,018		73,018
	g.	Big Bend Unit 2 Classifier Replacement	7	4,522	4,503	4,482	4,463	4,444	4,424	4,423	4,403	4,384	4,364	4,345	4,324	53,081		53,081
	h.	Big Bend Section 114 Mercury Testing Platform	8	688	686	684	682	681	678	682	680	678	676	674	672	8,161		8,161
	i.	Big Bend Units 1 & 2 FGD	9	478,583	476,901	475,221	473,540	471,860	470,179	471,229	469,526	467,824	466,120	464,417	462,715	5,648,115		5,648,115
	j.	Big Bend FGD Optimization and Utilization	10	129,227	128,921	128,615	128,309	128,004	127,698	128,447	128,137	127,827	127,518	127,207	126,897	1,536,807		1,536,807
	k.	Big Bend NO_x Emissions Reduction	11	41,071	41,006	40,940	40,875	40,810	40,744	41,082	41,016	40,950	40,883	40,817	40,751	490,945		490,945
	l.	Big Bend PM Minimization and Monitoring	12	145,465	145,074	144,683	144,292	143,902	143,511	144,208	143,812	143,416	143,020	142,625	142,229	1,726,237		1,726,237
	m.	Polk NO_x Emissions Reduction	13	9,023	8,995	8,967	8,938	8,910	8,881	8,911	8,882	8,854	8,825	8,797	8,767	106,750		106,750
	n.	Big Bend Unit 4 SOFA	14	15,974	15,934	15,893	15,852	15,810	15,769	15,852	15,811	15,769	15,727	15,685	15,644	189,720		189,720
	o.	Big Bend Unit 1 Pre-SCR	15	10,944	10,909	10,874	10,838	10,803	10,768	10,802	10,766	10,730	10,694	10,659	10,623	129,410		129,410
	p.	Big Bend Unit 2 Pre-SCR	16	10,447	10,416	10,385	10,353	10,322	10,291	10,331	10,299	10,267	10,236	10,204	10,173	123,724		123,724
	q.	Big Bend Unit 3 Pre-SCR	17	18,730	18,679	18,628	18,577	18,526	18,475	18,563	18,511	18,459	18,407	18,355	18,304	222,214		222,214
	r.	Big Bend Unit 1 SCR	18	625,491	623,508	621,523	619,540	617,555	615,572	617,612	615,602	613,592	611,582	609,572	607,562	7,398,711		7,398,711
	s.	Big Bend Unit 2 SCR	19	685,248	683,243	681,238	679,234	677,230	675,225	677,991	675,960	673,929	671,898	669,867	667,836	8,118,899		8,118,899
	t.	Big Bend Unit 3 SCR	20	557,845	556,227	554,610	552,992	551,374	549,757	552,053	550,414	548,776	547,136	545,498	543,858	6,610,540		6,610,540
	u.	Big Bend Unit 4 SCR	21	446,857	445,621	444,387	443,151	441,917	440,681	442,712	441,460	440,209	438,957	437,706	436,454	5,300,112		5,300,112
	v.	Big Bend FGD System Reliability	22	170,984	170,653	170,322	169,991	169,660	169,329	170,551	170,215	169,880	169,544	169,208	168,873	2,039,210		2,039,210
	w.	Mercury Air Toxics Standards	23	66,806	66,662	66,519	66,376	66,233	66,090	66,524	66,379	66,234	66,089	65,944	65,799	795,655		795,655
	x.	SO_2 Emissions Allowances (B)	24	(220)	(220)	(220)	(220)	(220)	(220)	(223)	(223)	(223)	(223)	(223)	(223)	(2,658)		(2,658)
	y.	Big Bend Gypsum Storage Facility	25	169,224	168,891	168,558	168,225	167,892	167,559	168,751	168,414	168,077	167,740	167,402	167,065	2,017,798		2,017,798
	z.	Big Bend CCR Rule - Phase I	26	9,841	9,886	9,913	9,937	9,995	10,099	11,277	13,451	16,268	19,400	21,121	21,386	162,574	162,574	
	aa.	Big Bend CCR Rule - Phase II	27	4,432	4,563	4,731	4,924	5,163	5,505	5,868	7,668	11,070	14,464	18,341	21,727	108,456	108,456	
	ab.	Big Bend ELG Compliance	28	907	931	1,016	1,153	1,292	1,446	2,389	5,114	8,875	13,329	18,475	24,377	79,304	79,304	
	ac.	Big Bend Unit 1 Sec. 316(b) Impingement Mortality	29	395	431	718	1,051	1,196	1,530	1,907	2,255	4,034	5,657	5,946	6,485	31,605	31,605	
2.		Total Investment Projects - Recoverable Costs		3,725,028	3,714,545	3,704,392	3,694,361	3,684,230	3,674,442	3,692,699	3,688,884	3,689,789	3,691,528	3,691,703	3,690,935	44,342,536	$563,409	$43,779,127
3.		Recoverable Costs Allocated to Energy		3,693,861	3,683,229	3,672,597	3,661,965	3,651,339	3,640,704	3,656,168	3,645,394	3,634,627	3,623,851	3,613,082	3,602,310	43,779,127		43,779,127
4.		Recoverable Costs Allocated to Demand		31,167	31,316	31,795	32,396	32,891	33,738	36,531	43,490	55,162	67,677	78,621	88,625	563,409	563,409	
5.		Retail Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.		Retail Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.		Jurisdictional Energy Recoverable Costs (C)		3,693,861	3,683,229	3,672,597	3,661,965	3,651,339	3,640,704	3,656,168	3,645,394	3,634,627	3,623,851	3,613,082	3,602,310	43,779,127		
8.		Jurisdictional Demand Recoverable Costs (D)		31,167	31,316	31,795	32,396	32,891	33,738	36,531	43,490	55,162	67,677	78,621	88,625	563,409		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$3,725,028	$3,714,545	$3,704,392	$3,694,361	$3,684,230	$3,674,442	$3,692,699	$3,688,884	$3,689,789	$3,691,528	$3,691,703	$3,690,935	$44,342,536		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9
(B) Project's Total Return Component on Form 42-8A, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

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ECRC 2020 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

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)	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	
3.	Less: Accumulated Depreciation	(6,132,393)	(6,161,231)	(6,190,069)	(6,218,907)	(6,247,745)	(6,276,583)	(6,305,421)	(6,334,259)	(6,363,097)	(6,391,935)	(6,420,773)	(6,449,611)	(6,478,449)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,630,870	$7,602,032	$7,573,194	$7,544,356	$7,515,518	$7,486,680	$7,457,842	$7,429,004	$7,400,166	$7,371,328	$7,342,490	$7,313,652	$7,284,814	
6.	Average Net Investment		7,616,451	7,587,613	7,558,775	7,529,937	7,501,099	7,472,261	7,443,423	7,414,585	7,385,747	7,356,909	7,328,071	7,299,233	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$37,851	$37,707	$37,564	$37,421	$37,277	$37,134	$37,277	$37,132	$36,988	$36,843	$36,699	$36,555	$446,448
	b. Debt Component Grossed Up For Taxes (C)		11,024	10,982	10,941	10,899	10,857	10,815	11,119	11,076	11,033	10,990	10,947	10,904	131,587
8.	Investment Expenses														
	a. Depreciation (D)		28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	346,056
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		77,713	77,527	77,343	77,158	76,972	76,787	77,234	77,046	76,859	76,671	76,484	76,297	924,091
	a. Recoverable Costs Allocated to Energy		77,713	77,527	77,343	77,158	76,972	76,787	77,234	77,046	76,859	76,671	76,484	76,297	924,091
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		77,713	77,527	77,343	77,158	76,972	76,787	77,234	77,046	76,859	76,671	76,484	76,297	924,091
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$77,713	$77,527	$77,343	$77,158	$76,972	$76,787	$77,234	$77,046	$76,859	$76,671	$76,484	$76,297	$924,091

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775), 315.45 ($327,307), and 312.40 ($182).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5%, 3.1%, and 3.4%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(4,566,662)	(4,582,803)	(4,598,944)	(4,615,085)	(4,631,226)	(4,647,367)	(4,663,508)	(4,679,649)	(4,695,790)	(4,711,931)	(4,728,072)	(4,744,213)	(4,760,354)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$451,072	$434,931	$418,790	$402,649	$386,508	$370,367	$354,226	$338,085	$321,944	$305,803	$289,662	$273,521	$257,380	
6.	Average Net Investment		443,002	426,861	410,720	394,579	378,438	362,297	346,156	330,015	313,874	297,733	281,592	265,451	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$2,202	$2,121	$2,041	$1,961	$1,881	$1,800	$1,734	$1,653	$1,572	$1,491	$1,410	$1,329	$21,195
	b. Debt Component Grossed Up For Taxes (C)		641	618	594	571	548	524	517	493	469	445	421	397	6,238
8.	Investment Expenses														
	a. Depreciation (D)		16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	193,692
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,984	18,880	18,776	18,673	18,570	18,465	18,392	18,287	18,182	18,077	17,972	17,867	221,125
	a. Recoverable Costs Allocated to Energy		18,984	18,880	18,776	18,673	18,570	18,465	18,392	18,287	18,182	18,077	17,972	17,867	221,125
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		18,984	18,880	18,776	18,673	18,570	18,465	18,392	18,287	18,182	18,077	17,972	17,867	221,125
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,984	$18,880	$18,776	$18,673	$18,570	$18,465	$18,392	$18,287	$18,182	$18,077	$17,972	$17,867	$221,125

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation 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 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(597,605)	(599,915)	(602,225)	(604,535)	(606,845)	(609,155)	(611,465)	(613,775)	(616,085)	(618,395)	(620,705)	(623,015)	(625,325)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$268,606	$266,296	$263,986	$261,676	$259,366	$257,056	$254,746	$252,436	$250,126	$247,816	$245,506	$243,196	$240,886	
6.	Average Net Investment		267,451	265,141	262,831	260,521	258,211	255,901	253,591	251,281	248,971	246,661	244,351	242,041	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,329	$1,318	$1,306	$1,295	$1,283	$1,272	$1,270	$1,258	$1,247	$1,235	$1,224	$1,212	$15,249
	b. Debt Component Grossed Up For Taxes (C)		387	384	380	377	374	370	379	375	372	368	365	362	4,493
8.	Investment Expenses														
	a. Depreciation (D)		2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	27,720
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,026	4,012	3,996	3,982	3,967	3,952	3,959	3,943	3,929	3,913	3,899	3,884	47,462
	a. Recoverable Costs Allocated to Energy		4,026	4,012	3,996	3,982	3,967	3,952	3,959	3,943	3,929	3,913	3,899	3,884	47,462
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,026	4,012	3,996	3,982	3,967	3,952	3,959	3,943	3,929	3,913	3,899	3,884	47,462
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,026	$4,012	$3,996	$3,982	$3,967	$3,952	$3,959	$3,943	$3,929	$3,913	$3,899	$3,884	$47,462

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(374,626)	(379,749)	(384,872)	(389,995)	(395,118)	(400,241)	(405,364)	(410,487)	(415,610)	(420,733)	(425,856)	(430,979)	(436,102)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$122,952	$117,829	$112,706	$107,583	$102,460	$97,337	$92,214	$87,091	$81,968	$76,845	$71,722	$66,599	$61,476	
6.	Average Net Investment		120,391	115,268	110,145	105,022	99,899	94,776	89,653	84,530	79,407	74,284	69,161	64,038	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$598	$573	$547	$522	$496	$471	$449	$423	$398	$372	$346	$321	$5,516
	b. Debt Component Grossed Up For Taxes (C)		174	167	159	152	145	137	134	126	119	111	103	96	1,623
8.	Investment Expenses														
	a. Depreciation (D)		5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,476
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		5,895	5,863	5,829	5,797	5,764	5,731	5,706	5,672	5,640	5,606	5,572	5,540	68,615
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		5,895	5,863	5,829	5,797	5,764	5,731	5,706	5,672	5,640	5,606	5,572	5,540	68,615
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		5,895	5,863	5,829	5,797	5,764	5,731	5,706	5,672	5,640	5,606	5,572	5,540	68,615
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,895	$5,863	$5,829	$5,797	$5,764	$5,731	$5,706	$5,672	$5,640	$5,606	$5,572	$5,540	$68,615

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(616,174)	(624,600)	(633,026)	(641,452)	(649,878)	(658,304)	(666,730)	(675,156)	(683,582)	(692,008)	(700,434)	(708,860)	(717,286)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$202,227	$193,801	$185,375	$176,949	$168,523	$160,097	$151,671	$143,245	$134,819	$126,393	$117,967	$109,541	$101,115	
6.	Average Net Investment		198,014	189,588	181,162	172,736	164,310	155,884	147,458	139,032	130,606	122,180	113,754	105,328	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$984	$942	$900	$858	$817	$775	$738	$696	$654	$612	$570	$527	$9,073
	b. Debt Component Grossed Up For Taxes (C)		287	274	262	250	238	226	220	208	195	183	170	157	2,670
8.	Investment Expenses														
	a. Depreciation (D)		8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	101,112
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,697	9,642	9,588	9,534	9,481	9,427	9,384	9,330	9,275	9,221	9,166	9,110	112,855
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		9,697	9,642	9,588	9,534	9,481	9,427	9,384	9,330	9,275	9,221	9,166	9,110	112,855
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		9,697	9,642	9,588	9,534	9,481	9,427	9,384	9,330	9,275	9,221	9,166	9,110	112,855
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,697	$9,642	$9,588	$9,534	$9,481	$9,427	$9,384	$9,330	$9,275	$9,221	$9,166	$9,110	$112,855

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
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January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(1,027,160)	(1,031,548)	(1,035,936)	(1,040,324)	(1,044,712)	(1,049,100)	(1,053,488)	(1,057,876)	(1,062,264)	(1,066,652)	(1,071,040)	(1,075,428)	(1,079,816)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$289,097	$284,709	$280,321	$275,933	$271,545	$267,157	$262,769	$258,381	$253,993	$249,605	$245,217	$240,829	$236,441	
6.	Average Net Investment		286,903	282,515	278,127	273,739	269,351	264,963	260,575	256,187	251,799	247,411	243,023	238,635	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,426	$1,404	$1,382	$1,360	$1,339	$1,317	$1,305	$1,283	$1,261	$1,239	$1,217	$1,195	$15,728
	b. Debt Component Grossed Up For Taxes (C)		415	409	403	396	390	384	389	383	376	370	363	356	4,634
8.	Investment Expenses														
	a. Depreciation (D)		4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	52,656
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,229	6,201	6,173	6,144	6,117	6,089	6,082	6,054	6,025	5,997	5,968	5,939	73,018
	a. Recoverable Costs Allocated to Energy		6,229	6,201	6,173	6,144	6,117	6,089	6,082	6,054	6,025	5,997	5,968	5,939	73,018
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		6,229	6,201	6,173	6,144	6,117	6,089	6,082	6,054	6,025	5,997	5,968	5,939	73,018
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,229	$6,201	$6,173	$6,144	$6,117	$6,089	$6,082	$6,054	$6,025	$5,997	$5,968	$5,939	$73,018

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(751,734)	(754,770)	(757,806)	(760,842)	(763,878)	(766,914)	(769,950)	(772,986)	(776,022)	(779,058)	(782,094)	(785,130)	(788,166)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$233,060	$230,024	$226,988	$223,952	$220,916	$217,880	$214,844	$211,808	$208,772	$205,736	$202,700	$199,664	$196,628	
6.	Average Net Investment		231,542	228,506	225,470	222,434	219,398	216,362	213,326	210,290	207,254	204,218	201,182	198,146	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,151	$1,136	$1,120	$1,105	$1,090	$1,075	$1,068	$1,053	$1,038	$1,023	$1,008	$992	$12,859
	b. Debt Component Grossed Up For Taxes (C)		335	331	326	322	318	313	319	314	310	305	301	296	3,790
8.	Investment Expenses														
	a. Depreciation (D)		3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	36,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,522	4,503	4,482	4,463	4,444	4,424	4,423	4,403	4,384	4,364	4,345	4,324	53,081
	a. Recoverable Costs Allocated to Energy		4,522	4,503	4,482	4,463	4,444	4,424	4,423	4,403	4,384	4,364	4,345	4,324	53,081
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,522	4,503	4,482	4,463	4,444	4,424	4,423	4,403	4,384	4,364	4,345	4,324	53,081
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,522	$4,503	$4,482	$4,463	$4,444	$4,424	$4,423	$4,403	$4,384	$4,364	$4,345	$4,324	$53,081

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(58,915)	(59,207)	(59,499)	(59,791)	(60,083)	(60,375)	(60,667)	(60,959)	(61,251)	(61,543)	(61,835)	(62,127)	(62,419)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$61,822	$61,530	$61,238	$60,946	$60,654	$60,362	$60,070	$59,778	$59,486	$59,194	$58,902	$58,610	$58,318	
6.	Average Net Investment		61,676	61,384	61,092	60,800	60,508	60,216	59,924	59,632	59,340	59,048	58,756	58,464	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$307	$305	$304	$302	$301	$299	$300	$299	$297	$296	$294	$293	$3,597
	b. Debt Component Grossed Up For Taxes (C)		89	89	88	88	88	87	90	89	89	88	88	87	1,060
8.	Investment Expenses														
	a. Depreciation (D)		292	292	292	292	292	292	292	292	292	292	292	292	3,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		688	686	684	682	681	678	682	680	678	676	674	672	8,161
	a. Recoverable Costs Allocated to Energy		688	686	684	682	681	678	682	680	678	676	674	672	8,161
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		688	686	684	682	681	678	682	680	678	676	674	672	8,161
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$688	$686	$684	$682	$681	$678	$682	$680	$678	$676	$674	$672	$8,161

Notes:

(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(61,360,265)	(61,622,184)	(61,884,103)	(62,146,022)	(62,407,941)	(62,669,860)	(62,931,779)	(63,193,698)	(63,455,617)	(63,717,536)	(63,979,455)	(64,241,374)	(64,503,293)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$33,894,977	$33,633,058	$33,371,139	$33,109,220	$32,847,301	$32,585,382	$32,323,463	$32,061,544	$31,799,625	$31,537,706	$31,275,787	$31,013,868	$30,751,949	
6.	Average Net Investment		33,764,017	33,502,098	33,240,179	32,978,260	32,716,341	32,454,422	32,192,503	31,930,584	31,668,665	31,406,746	31,144,827	30,882,908	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$167,793	$166,491	$165,190	$163,888	$162,587	$161,285	$161,220	$159,908	$158,597	$157,285	$155,973	$154,662	$1,934,879
	b. Debt Component Grossed Up For Taxes (C)		48,871	48,491	48,112	47,733	47,354	46,975	48,090	47,699	47,308	46,916	46,525	46,134	570,208
8.	Investment Expenses														
	a. Depreciation (D)		261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	3,143,028
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		478,583	476,901	475,221	473,540	471,860	470,179	471,229	469,526	467,824	466,120	464,417	462,715	5,648,115
	a. Recoverable Costs Allocated to Energy		478,583	476,901	475,221	473,540	471,860	470,179	471,229	469,526	467,824	466,120	464,417	462,715	5,648,115
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		478,583	476,901	475,221	473,540	471,860	470,179	471,229	469,526	467,824	466,120	464,417	462,715	5,648,115
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$478,583	$476,901	$475,221	$473,540	$471,860	$470,179	$471,229	$469,526	$467,824	$466,120	$464,417	$462,715	$5,648,115

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($105,398), 312.46 ($94,929,061) & 315.46 ($220,782)
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5%, 3.3% and 3.5%
(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 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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)	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	
3.	Less: Accumulated Depreciation	(9,917,006)	(9,964,653)	(10,012,300)	(10,059,947)	(10,107,594)	(10,155,241)	(10,202,888)	(10,250,535)	(10,298,182)	(10,345,829)	(10,393,476)	(10,441,123)	(10,488,770)	
4.	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$12,736,923	$12,689,276	$12,641,629	$12,593,982	$12,546,335	$12,498,688	$12,451,041	$12,403,394	$12,355,747	$12,308,100	$12,260,453	$12,212,806	$12,165,159	
6.	Average Net Investment		12,713,100	12,665,453	12,617,806	12,570,159	12,522,512	12,474,865	12,427,218	12,379,571	12,331,924	12,284,277	12,236,630	12,188,983	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$63,179	$62,942	$62,705	$62,468	$62,232	$61,995	$62,236	$61,997	$61,758	$61,520	$61,281	$61,042	$745,355
	b. Debt Component Grossed Up For Taxes (C)		18,401	18,332	18,263	18,194	18,125	18,056	18,564	18,493	18,422	18,351	18,279	18,208	219,688
8.	Investment Expenses														
	a. Depreciation (D)		47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	571,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		129,227	128,921	128,615	128,309	128,004	127,698	128,447	128,137	127,827	127,518	127,207	126,897	1,536,807
	a. Recoverable Costs Allocated to Energy		129,227	128,921	128,615	128,309	128,004	127,698	128,447	128,137	127,827	127,518	127,207	126,897	1,536,807
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		129,227	128,921	128,615	128,309	128,004	127,698	128,447	128,137	127,827	127,518	127,207	126,897	1,536,807
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$129,227	$128,921	$128,615	$128,309	$128,004	$127,698	$128,447	$128,137	$127,827	$127,518	$127,207	$126,897	$1,536,807

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,855,886), 311.45 ($40,016), 316.40 ($71,401), 315.45 ($594,901), 312.42 ($1,637), and 312.40 ($90,088)
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5%, 2.0%, 4.2%, 3.1%, 3.7%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	1,627,563	1,617,379	1,607,195	1,597,011	1,586,827	1,576,643	1,566,459	1,556,275	1,546,091	1,535,907	1,525,723	1,515,539	1,505,355	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,818,415	$4,808,231	$4,798,047	$4,787,863	$4,777,679	$4,767,495	$4,757,311	$4,747,127	$4,736,943	$4,726,759	$4,716,575	$4,706,391	$4,696,207	
6.	Average Net Investment		4,813,323	4,803,139	4,792,955	4,782,771	4,772,587	4,762,403	4,752,219	4,742,035	4,731,851	4,721,667	4,711,483	4,701,299	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$23,920	$23,870	$23,819	$23,768	$23,718	$23,667	$23,799	$23,748	$23,697	$23,646	$23,595	$23,544	$284,791
	b. Debt Component Grossed Up For Taxes (C)		6,967	6,952	6,937	6,923	6,908	6,893	7,099	7,084	7,069	7,053	7,038	7,023	83,946
8.	Investment Expenses														
	a. Depreciation (D)		10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		41,071	41,006	40,940	40,875	40,810	40,744	41,082	41,016	40,950	40,883	40,817	40,751	490,945
	a. Recoverable Costs Allocated to Energy		41,071	41,006	40,940	40,875	40,810	40,744	41,082	41,016	40,950	40,883	40,817	40,751	490,945
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		41,071	41,006	40,940	40,875	40,810	40,744	41,082	41,016	40,950	40,883	40,817	40,751	490,945
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$41,071	$41,006	$40,940	$40,875	$40,810	$40,744	$41,082	$41,016	$40,950	$40,883	$40,817	$40,751	$490,945

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 4.0%, 3.7%, and 3.5%
(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 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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)	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	
3.	Less: Accumulated Depreciation	(6,544,786)	(6,605,658)	(6,666,530)	(6,727,402)	(6,788,274)	(6,849,146)	(6,910,018)	(6,970,890)	(7,031,762)	(7,092,634)	(7,153,506)	(7,214,378)	(7,275,250)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$13,212,964	$13,152,092	$13,091,220	$13,030,348	$12,969,476	$12,908,604	$12,847,732	$12,786,860	$12,725,988	$12,665,116	$12,604,244	$12,543,372	$12,482,500	
6.	Average Net Investment		13,182,528	13,121,656	13,060,784	12,999,912	12,939,040	12,878,168	12,817,296	12,756,424	12,695,552	12,634,680	12,573,808	12,512,936	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$65,512	$65,209	$64,907	$64,604	$64,302	$63,999	$64,189	$63,884	$63,579	$63,274	$62,970	$62,665	$769,094
	b. Debt Component Grossed Up For Taxes (C)		19,081	18,993	18,904	18,816	18,728	18,640	19,147	19,056	18,965	18,874	18,783	18,692	226,679
8.	Investment Expenses														
	a. Depreciation (D)		60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	730,464
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		145,465	145,074	144,683	144,292	143,902	143,511	144,208	143,812	143,416	143,020	142,625	142,229	1,726,237
	a. Recoverable Costs Allocated to Energy		145,465	145,074	144,683	144,292	143,902	143,511	144,208	143,812	143,416	143,020	142,625	142,229	1,726,237
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		145,465	145,074	144,683	144,292	143,902	143,511	144,208	143,812	143,416	143,020	142,625	142,229	1,726,237
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$145,465	$145,074	$144,683	$144,292	$143,902	$143,511	$144,208	$143,812	$143,416	$143,020	$142,625	$142,229	$1,726,237

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($5,831,465), 312.42 ($5,153,072), 312.43 ($7,875,560), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554)
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation 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 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(842,586)	(847,010)	(851,434)	(855,858)	(860,282)	(864,706)	(869,130)	(873,554)	(877,978)	(882,402)	(886,826)	(891,250)	(895,674)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$718,887	$714,463	$710,039	$705,615	$701,191	$696,767	$692,343	$687,919	$683,495	$679,071	$674,647	$670,223	$665,799	
6.	Average Net Investment		716,675	712,251	707,827	703,403	698,979	694,555	690,131	685,707	681,283	676,859	672,435	668,011	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,562	$3,540	$3,518	$3,496	$3,474	$3,452	$3,456	$3,434	$3,412	$3,390	$3,368	$3,345	$41,447
	b. Debt Component Grossed Up For Taxes (C)		1,037	1,031	1,025	1,018	1,012	1,005	1,031	1,024	1,018	1,011	1,005	998	12,215
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,023	8,995	8,967	8,938	8,910	8,881	8,911	8,882	8,854	8,825	8,797	8,767	106,750
	a. Recoverable Costs Allocated to Energy		9,023	8,995	8,967	8,938	8,910	8,881	8,911	8,882	8,854	8,825	8,797	8,767	106,750
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		9,023	8,995	8,967	8,938	8,910	8,881	8,911	8,882	8,854	8,825	8,797	8,767	106,750
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,023	$8,995	$8,967	$8,938	$8,910	$8,881	$8,911	$8,882	$8,854	$8,825	$8,797	$8,767	$106,750

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(1,062,962)	(1,069,359)	(1,075,756)	(1,082,153)	(1,088,550)	(1,094,947)	(1,101,344)	(1,107,741)	(1,114,138)	(1,120,535)	(1,126,932)	(1,133,329)	(1,139,726)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,495,768	$1,489,371	$1,482,974	$1,476,577	$1,470,180	$1,463,783	$1,457,386	$1,450,989	$1,444,592	$1,438,195	$1,431,798	$1,425,401	$1,419,004	
6.	Average Net Investment		1,492,570	1,486,173	1,479,776	1,473,379	1,466,982	1,460,585	1,454,188	1,447,791	1,441,394	1,434,997	1,428,600	1,422,203	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,417	$7,386	$7,354	$7,322	$7,290	$7,258	$7,283	$7,251	$7,219	$7,186	$7,154	$7,122	$87,242
	b. Debt Component Grossed Up For Taxes (C)		2,160	2,151	2,142	2,133	2,123	2,114	2,172	2,163	2,153	2,144	2,134	2,125	25,714
8.	Investment Expenses														
	a. Depreciation (D)		6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	76,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		15,974	15,934	15,893	15,852	15,810	15,769	15,852	15,811	15,769	15,727	15,685	15,644	189,720
	a. Recoverable Costs Allocated to Energy		15,974	15,934	15,893	15,852	15,810	15,769	15,852	15,811	15,769	15,727	15,685	15,644	189,720
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		15,974	15,934	15,893	15,852	15,810	15,769	15,852	15,811	15,769	15,727	15,685	15,644	189,720
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,974	$15,934	$15,893	$15,852	$15,810	$15,769	$15,852	$15,811	$15,769	$15,727	$15,685	$15,644	$189,720

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(797,557)	(803,054)	(808,551)	(814,048)	(819,545)	(825,042)	(830,539)	(836,036)	(841,533)	(847,030)	(852,527)	(858,024)	(863,521)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$851,564	$846,067	$840,570	$835,073	$829,576	$824,079	$818,582	$813,085	$807,588	$802,091	$796,594	$791,097	$785,600	
6.	Average Net Investment		848,816	843,319	837,822	832,325	826,828	821,331	815,834	810,337	804,840	799,343	793,846	788,349	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,218	$4,191	$4,164	$4,136	$4,109	$4,082	$4,086	$4,058	$4,031	$4,003	$3,976	$3,948	$49,002
	b. Debt Component Grossed Up For Taxes (C)		1,229	1,221	1,213	1,205	1,197	1,189	1,219	1,211	1,202	1,194	1,186	1,178	14,444
8.	Investment Expenses														
	a. Depreciation (D)		5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	65,964
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,944	10,909	10,874	10,838	10,803	10,768	10,802	10,766	10,730	10,694	10,659	10,623	129,410
	a. Recoverable Costs Allocated to Energy		10,944	10,909	10,874	10,838	10,803	10,768	10,802	10,766	10,730	10,694	10,659	10,623	129,410
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,944	10,909	10,874	10,838	10,803	10,768	10,802	10,766	10,730	10,694	10,659	10,623	129,410
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,944	$10,909	$10,874	$10,838	$10,803	$10,768	$10,802	$10,766	$10,730	$10,694	$10,659	$10,623	$129,410

Notes:

(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(711,368)	(716,245)	(721,122)	(725,999)	(730,876)	(735,753)	(740,630)	(745,507)	(750,384)	(755,261)	(760,138)	(765,015)	(769,892)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$870,519	$865,642	$860,765	$855,888	$851,011	$846,134	$841,257	$836,380	$831,503	$826,626	$821,749	$816,872	$811,995	
6.	Average Net Investment		868,081	863,204	858,327	853,450	848,573	843,696	838,819	833,942	829,065	824,188	819,311	814,434	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,314	$4,290	$4,266	$4,241	$4,217	$4,193	$4,201	$4,176	$4,152	$4,128	$4,103	$4,079	$50,360
	b. Debt Component Grossed Up For Taxes (C)		1,256	1,249	1,242	1,235	1,228	1,221	1,253	1,246	1,238	1,231	1,224	1,217	14,840
8.	Investment Expenses														
	a. Depreciation (D)		4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,447	10,416	10,385	10,353	10,322	10,291	10,331	10,299	10,267	10,236	10,204	10,173	123,724
	a. Recoverable Costs Allocated to Energy		10,447	10,416	10,385	10,353	10,322	10,291	10,331	10,299	10,267	10,236	10,204	10,173	123,724
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,447	10,416	10,385	10,353	10,322	10,291	10,331	10,299	10,267	10,236	10,204	10,173	123,724
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,447	$10,416	$10,385	$10,353	$10,322	$10,291	$10,331	$10,299	$10,267	$10,236	$10,204	$10,173	$123,724

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(1,023,074)	(1,031,027)	(1,038,980)	(1,046,933)	(1,054,886)	(1,062,839)	(1,070,792)	(1,078,745)	(1,086,698)	(1,094,651)	(1,102,604)	(1,110,557)	(1,118,510)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,683,433	$1,675,480	$1,667,527	$1,659,574	$1,651,621	$1,643,668	$1,635,715	$1,627,762	$1,619,809	$1,611,856	$1,603,903	$1,595,950	$1,587,997	
6.	Average Net Investment		1,679,457	1,671,504	1,663,551	1,655,598	1,647,645	1,639,692	1,631,739	1,623,786	1,615,833	1,607,880	1,599,927	1,591,974	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$8,346	$8,307	$8,267	$8,228	$8,188	$8,149	$8,172	$8,132	$8,092	$8,052	$8,012	$7,973	$97,918
	b. Debt Component Grossed Up For Taxes (C)		2,431	2,419	2,408	2,396	2,385	2,373	2,438	2,426	2,414	2,402	2,390	2,378	28,860
8.	Investment Expenses														
	a. Depreciation (D)		7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,730	18,679	18,628	18,577	18,526	18,475	18,563	18,511	18,459	18,407	18,355	18,304	222,214
	a. Recoverable Costs Allocated to Energy		18,730	18,679	18,628	18,577	18,526	18,475	18,563	18,511	18,459	18,407	18,355	18,304	222,214
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		18,730	18,679	18,628	18,577	18,526	18,475	18,563	18,511	18,459	18,407	18,355	18,304	222,214
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,730	$18,679	$18,628	$18,577	$18,526	$18,475	$18,563	$18,511	$18,459	$18,407	$18,355	$18,304	$222,214

Notes:

(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(36,269,622)	(36,578,788)	(36,887,954)	(37,197,120)	(37,506,286)	(37,815,452)	(38,124,618)	(38,433,784)	(38,742,950)	(39,052,116)	(39,361,282)	(39,670,448)	(39,979,614)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$49,449,480	$49,140,314	$48,831,148	$48,521,982	$48,212,816	$47,903,650	$47,594,484	$47,285,318	$46,976,152	$46,666,986	$46,357,820	$46,048,654	$45,739,488	
6.	Average Net Investment		49,294,897	48,985,731	48,676,565	48,367,399	48,058,233	47,749,067	47,439,901	47,130,735	46,821,569	46,512,403	46,203,237	45,894,071	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$244,975	$243,439	$241,902	$240,366	$238,829	$237,293	$237,579	$236,031	$234,482	$232,934	$231,386	$229,838	$2,849,054
	b. Debt Component Grossed Up For Taxes (C)		71,350	70,903	70,455	70,008	69,560	69,113	70,867	70,405	69,944	69,482	69,020	68,558	839,665
8.	Investment Expenses														
	a. Depreciation (D)		309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	309,166	3,709,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		625,491	623,508	621,523	619,540	617,555	615,572	617,612	615,602	613,592	611,582	609,572	607,562	7,398,711
	a. Recoverable Costs Allocated to Energy		625,491	623,508	621,523	619,540	617,555	615,572	617,612	615,602	613,592	611,582	609,572	607,562	7,398,711
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		625,491	623,508	621,523	619,540	617,555	615,572	617,612	615,602	613,592	611,582	609,572	607,562	7,398,711
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$625,491	$623,508	$621,523	$619,540	$617,555	$615,572	$617,612	$615,602	$613,592	$611,582	$609,572	$607,562	$7,398,711

Notes:

(A) Applicable depreciable base for Big Bend; 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 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8% and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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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)	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	
3.	Less: Accumulated Depreciation	(38,275,236)	(38,587,613)	(38,899,990)	(39,212,367)	(39,524,744)	(39,837,121)	(40,149,498)	(40,461,875)	(40,774,252)	(41,086,629)	(41,399,006)	(41,711,383)	(42,023,760)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$58,262,897	$57,950,520	$57,638,143	$57,325,766	$57,013,389	$56,701,012	$56,388,635	$56,076,258	$55,763,881	$55,451,504	$55,139,127	$54,826,750	$54,514,373	
6.	Average Net Investment		58,106,708	57,794,331	57,481,954	57,169,577	56,857,200	56,544,823	56,232,446	55,920,069	55,607,692	55,295,315	54,982,938	54,670,561	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$288,766	$287,214	$285,661	$284,109	$282,557	$281,004	$281,612	$280,048	$278,483	$276,919	$275,355	$273,790	$3,375,518
	b. Debt Component Grossed Up For Taxes (C)		84,105	83,652	83,200	82,748	82,296	81,844	84,002	83,535	83,069	82,602	82,135	81,669	994,857
8.	Investment Expenses														
	a. Depreciation (D)		312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	3,748,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		685,248	683,243	681,238	679,234	677,230	675,225	677,991	675,960	673,929	671,898	669,867	667,836	8,118,899
	a. Recoverable Costs Allocated to Energy		685,248	683,243	681,238	679,234	677,230	675,225	677,991	675,960	673,929	671,898	669,867	667,836	8,118,899
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		685,248	683,243	681,238	679,234	677,230	675,225	677,991	675,960	673,929	671,898	669,867	667,836	8,118,899
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$685,248	$683,243	$681,238	$679,234	$677,230	$675,225	$677,991	$675,960	$673,929	$671,898	$669,867	$667,836	$8,118,899

Notes:

(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($54,456,221), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(33,988,473)	(34,240,547)	(34,492,621)	(34,744,695)	(34,996,769)	(35,248,843)	(35,500,917)	(35,752,991)	(36,005,065)	(36,257,139)	(36,509,213)	(36,761,287)	(37,013,361)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$47,776,129	$47,524,055	$47,271,981	$47,019,907	$46,767,833	$46,515,759	$46,263,685	$46,011,611	$45,759,537	$45,507,463	$45,255,389	$45,003,315	$44,751,241	
6.	Average Net Investment		47,650,092	47,398,018	47,145,944	46,893,870	46,641,796	46,389,722	46,137,648	45,885,574	45,633,500	45,381,426	45,129,352	44,877,278	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$236,801	$235,548	$234,296	$233,043	$231,790	$230,538	$231,057	$229,795	$228,533	$227,270	$226,008	$224,745	$2,769,424
	b. Debt Component Grossed Up For Taxes (C)		68,970	68,605	68,240	67,875	67,510	67,145	68,922	68,545	68,169	67,792	67,416	67,039	816,228
8.	Investment Expenses														
	a. Depreciation (D)		252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	252,074	3,024,888
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		557,845	556,227	554,610	552,992	551,374	549,757	552,053	550,414	548,776	547,136	545,498	543,858	6,610,540
	a. Recoverable Costs Allocated to Energy		557,845	556,227	554,610	552,992	551,374	549,757	552,053	550,414	548,776	547,136	545,498	543,858	6,610,540
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		557,845	556,227	554,610	552,992	551,374	549,757	552,053	550,414	548,776	547,136	545,498	543,858	6,610,540
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$557,845	$556,227	$554,610	$552,992	$551,374	$549,757	$552,053	$550,414	$548,776	$547,136	$545,498	$543,858	$6,610,540

Notes:

(A) Applicable depreciable base for Big Bend; 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 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 3.1%, 3.9%, 4.0%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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)	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	
3.	Less: Accumulated Depreciation	(27,075,687)	(27,268,155)	(27,460,623)	(27,653,091)	(27,845,559)	(28,038,027)	(28,230,495)	(28,422,963)	(28,615,431)	(28,807,899)	(29,000,367)	(29,192,835)	(29,385,303)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$39,739,174	$39,546,706	$39,354,238	$39,161,770	$38,969,302	$38,776,834	$38,584,366	$38,391,898	$38,199,430	$38,006,962	$37,814,494	$37,622,026	$37,429,558	
6.	Average Net Investment		39,642,940	39,450,472	39,258,004	39,065,536	38,873,068	38,680,600	38,488,132	38,295,664	38,103,196	37,910,728	37,718,260	37,525,792	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$197,009	$196,052	$195,096	$194,139	$193,183	$192,226	$192,749	$191,785	$190,821	$189,857	$188,893	$187,929	$2,309,739
	b. Debt Component Grossed Up For Taxes (C)		57,380	57,101	56,823	56,544	56,266	55,987	57,495	57,207	56,920	56,632	56,345	56,057	680,757
8.	Investment Expenses														
	a. Depreciation (D)		192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	2,309,616
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		446,857	445,621	444,387	443,151	441,917	440,681	442,712	441,460	440,209	438,957	437,706	436,454	5,300,112
	a. Recoverable Costs Allocated to Energy		446,857	445,621	444,387	443,151	441,917	440,681	442,712	441,460	440,209	438,957	437,706	436,454	5,300,112
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		446,857	445,621	444,387	443,151	441,917	440,681	442,712	441,460	440,209	438,957	437,706	436,454	5,300,112
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$446,857	$445,621	$444,387	$443,151	$441,917	$440,681	$442,712	$441,460	$440,209	$438,957	$437,706	$436,454	$5,300,112

Notes:

(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($38,069,546), 315.54 ($10,642,027), 316.54 ($687,934), and 315.40 ($558,103)
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation 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 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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)	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	
3.	Less: Accumulated Depreciation	(5,834,881)	(5,886,463)	(5,938,045)	(5,989,627)	(6,041,209)	(6,092,791)	(6,144,373)	(6,195,955)	(6,247,537)	(6,299,119)	(6,350,701)	(6,402,283)	(6,453,865)	
4.	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$18,632,925	$18,581,343	$18,529,761	$18,478,179	$18,426,597	$18,375,015	$18,323,433	$18,271,851	$18,220,269	$18,168,687	$18,117,105	$18,065,523	$18,013,941	
6.	Average Net Investment		18,607,134	18,555,552	18,503,970	18,452,388	18,400,806	18,349,224	18,297,642	18,246,060	18,194,478	18,142,896	18,091,314	18,039,732	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$92,470	$92,213	$91,957	$91,701	$91,444	$91,188	$91,635	$91,376	$91,118	$90,860	$90,601	$90,343	$1,096,906
	b. Debt Component Grossed Up For Taxes (C)		26,932	26,858	26,783	26,708	26,634	26,559	27,334	27,257	27,180	27,102	27,025	26,948	323,320
8.	Investment Expenses														
	a. Depreciation (D)		51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	618,984
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		170,984	170,653	170,322	169,991	169,660	169,329	170,551	170,215	169,880	169,544	169,208	168,873	2,039,210
	a. Recoverable Costs Allocated to Energy		170,984	170,653	170,322	169,991	169,660	169,329	170,551	170,215	169,880	169,544	169,208	168,873	2,039,210
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		170,984	170,653	170,322	169,991	169,660	169,329	170,551	170,215	169,880	169,544	169,208	168,873	2,039,210
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$170,984	$170,653	$170,322	$169,991	$169,660	$169,329	$170,551	$170,215	$169,880	$169,544	$169,208	$168,873	$2,039,210

Notes:

(A) Applicable depreciable base for Big Bend; account 312.45 ($23,011,597) and 312.44 ($1,456,209).
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.5% and 3.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Environmental Cost Recovery Clause
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Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	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)	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	
3.	Less: Accumulated Depreciation	(1,687,707)	(1,710,003)	(1,732,299)	(1,754,595)	(1,776,891)	(1,799,187)	(1,821,483)	(1,843,779)	(1,866,075)	(1,888,371)	(1,910,667)	(1,932,963)	(1,955,259)	
4.	CWIP - Non-Interest Bearing	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	
5.	Net Investment (Lines 2 + 3 + 4)	$6,947,321	$6,925,025	$6,902,729	$6,880,433	$6,858,137	$6,835,841	$6,813,545	$6,791,249	$6,768,953	$6,746,657	$6,724,361	$6,702,065	$6,679,769	
6.	Average Net Investment		6,936,173	6,913,877	6,891,581	6,869,285	6,846,989	6,824,693	6,802,397	6,780,101	6,757,805	6,735,509	6,713,213	6,690,917	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$34,470	$34,359	$34,248	$34,137	$34,027	$33,916	$34,066	$33,955	$33,843	$33,731	$33,620	$33,508	$407,880
	b. Debt Component Grossed Up For Taxes (C)		10,040	10,007	9,975	9,943	9,910	9,878	10,162	10,128	10,095	10,062	10,028	9,995	120,223
8.	Investment Expenses														
	a. Depreciation (D)		22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	267,552
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,806	66,662	66,519	66,376	66,233	66,090	66,524	66,379	66,234	66,089	65,944	65,799	795,655
	a. Recoverable Costs Allocated to Energy		66,806	66,662	66,519	66,376	66,233	66,090	66,524	66,379	66,234	66,089	65,944	65,799	795,655
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		66,806	66,662	66,519	66,376	66,233	66,090	66,524	66,379	66,234	66,089	65,944	65,799	795,655
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$66,806	$66,662	$66,519	$66,376	$66,233	$66,090	$66,524	$66,379	$66,234	$66,089	$65,944	$65,799	$795,655

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.44 ($3,427,481), 341.80($26,150), 315.40 ($1,226,949), 315.41 ($138,853), 315.42 ($138,853), 312.45 ($2,053,017), 312.46 ($1,242,315), 315.44 ($16,035), 315.45 ($40,217) and 315.46 ($50,784), 311.40 ($13,216), 345.81 ($2,232), 312.54 ($210,295) and 395.00 ($35,018)

(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)

(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)

(D) Applicable depreciation rate is 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.2%, 3.1%, 3.5%, 2.9%, 3.3%, 3.8%, and 14.3%

(E) Line 9a x Line 10

(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	33	0	0	0	0	0	0	0	0	33
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(34,280)	(34,269)	(34,269)	(34,269)	(34,263)	(34,263)	(34,263)	(34,255)	(34,255)	(34,255)	(34,246)	(34,246)	(34,246)	
3.	Total Working Capital Balance	($34,280)	($34,269)	($34,269)	($34,269)	($34,263)	($34,263)	($34,263)	($34,255)	($34,255)	($34,255)	($34,246)	($34,246)	($34,246)	
4.	Average Net Working Capital Balance		($34,275)	($34,269)	($34,269)	($34,266)	($34,263)	($34,263)	($34,259)	($34,255)	($34,255)	($34,250)	($34,246)	($34,246)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($170)	($170)	($170)	($170)	($170)	($170)	($172)	($172)	($172)	($172)	($172)	($172)	(2,052)
	b. Debt Component Grossed Up For Taxes (B)		(50)	(50)	(50)	(50)	(50)	(50)	(51)	(51)	(51)	(51)	(51)	(51)	(606)
6.	Total Return Component		(220)	(220)	(220)	(220)	(220)	(220)	(223)	(223)	(223)	(223)	(223)	(223)	(2,658)
7.	Expenses:		1	2	3	4	5	6	7	8	9	10	11	12	
	a. Gains		0	0	0	(33)	0	0	0	0	0	0	0	0	(33)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		2	5	4	(6)	0	2	(4)	4	4	(4)	4	4	15
8.	Net Expenses (D)		2	5	4	(39)	0	2	(4)	4	4	(4)	4	4	(18)
9.	Total System Recoverable Expenses (Lines 6 + 8)		(218)	(215)	(216)	(259)	(220)	(218)	(227)	(219)	(219)	(227)	(219)	(219)	(2,676)
	a. Recoverable Costs Allocated to Energy		(218)	(215)	(216)	(259)	(220)	(218)	(227)	(219)	(219)	(227)	(219)	(219)	(2,676)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		(218)	(215)	(216)	(259)	(220)	(218)	(227)	(219)	(219)	(227)	(219)	(219)	(2,676)
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		($218)	($215)	($216)	($259)	($220)	($218)	($227)	($219)	($219)	($227)	($219)	($219)	($2,676)

Notes:

(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7144% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(C) Line 6 is reported on Schedule 7E.
(D) Line 8 is reported on Schedule 5E.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	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	(3,154,875)	(3,206,754)	(3,258,633)	(3,310,512)	(3,362,391)	(3,414,270)	(3,466,149)	(3,518,028)	(3,569,907)	(3,621,786)	(3,673,665)	(3,725,544)	(3,777,423)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$18,312,484	$18,260,605	$18,208,726	$18,156,847	$18,104,968	$18,053,089	$18,001,210	$17,949,331	$17,897,452	$17,845,573	$17,793,694	$17,741,815	$17,689,936	
6.	Average Net Investment		18,286,545	18,234,666	18,182,787	18,130,908	18,079,029	18,027,150	17,975,271	17,923,392	17,871,513	17,819,634	17,767,755	17,715,876	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$90,877	$90,619	$90,361	$90,103	$89,845	$89,587	$90,020	$89,760	$89,501	$89,241	$88,981	$88,721	$1,077,616
	b. Debt Component Grossed Up For Taxes (C)		26,468	26,393	26,318	26,243	26,168	26,093	26,852	26,775	26,697	26,620	26,542	26,465	317,634
8.	Investment Expenses														
	a. Depreciation (D)		51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	622,548
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		169,224	168,891	168,558	168,225	167,892	167,559	168,751	168,414	168,077	167,740	167,402	167,065	2,017,798
	a. Recoverable Costs Allocated to Energy		169,224	168,891	168,558	168,225	167,892	167,559	168,751	168,414	168,077	167,740	167,402	167,065	2,017,798
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		169,224	168,891	168,558	168,225	167,892	167,559	168,751	168,414	168,077	167,740	167,402	167,065	2,017,798
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$169,224	$168,891	$168,558	$168,225	$167,892	$167,559	$168,751	$168,414	$168,077	$167,740	$167,402	$167,065	$2,017,798

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend 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		$8,787	$9,800	$3,433	$8,328	$14,211	$23,138	$312,000	$361,300	$510,000	$458,043	$76,000	$10,000	$1,795,040
	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)	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	$930,303	
3.	Less: Accumulated Depreciation	(50,121)	(52,425)	(54,729)	(57,033)	(59,337)	(61,641)	(63,945)	(66,249)	(68,553)	(70,857)	(73,161)	(75,465)	(77,769)	
4.	CWIP - Non-Interest Bearing	291,146	299,934	309,734	313,167	321,494	335,706	358,844	670,844	1,032,144	1,542,144	2,000,187	2,076,187	2,086,187	
5.	Net Investment (Lines 2 + 3 + 4)	$1,171,328	$1,177,812	$1,185,308	$1,186,437	$1,192,460	$1,204,368	$1,225,202	$1,534,898	$1,893,894	$2,401,590	$2,857,329	$2,931,025	$2,938,721	
6.	Average Net Investment		1,174,570	1,181,560	1,185,873	1,189,449	1,198,414	1,214,785	1,380,050	1,714,396	2,147,742	2,629,460	2,894,177	2,934,873	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$5,837	$5,872	$5,893	$5,911	$5,956	$6,037	$6,911	$8,586	$10,756	$13,168	$14,494	$14,698	$104,119
	b. Debt Component Grossed Up For Taxes (C)		1,700	1,710	1,716	1,722	1,735	1,758	2,062	2,561	3,208	3,928	4,323	4,384	30,807
8.	Investment Expenses														
	a. Depreciation (D)		2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	2,304	27,648
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,841	9,886	9,913	9,937	9,995	10,099	11,277	13,451	16,268	19,400	21,121	21,386	162,574
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		9,841	9,886	9,913	9,937	9,995	10,099	11,277	13,451	16,268	19,400	21,121	21,386	162,574
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		9,841	9,886	9,913	9,937	9,995	10,099	11,277	13,451	16,268	19,400	21,121	21,386	162,574
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,841	$9,886	$9,913	$9,937	$9,995	$10,099	$11,277	$13,451	$16,268	$19,400	$21,121	$21,386	$162,574

Notes:

(A) Applicable depreciable base for Big Bend ; accounts 311.40 ($261,568) and 312.44 ($668,735)
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9% and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend 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		$17,515	$23,385	$29,109	$30,920	$43,592	$62,914	$26,500	$527,000	$519,745	$524,309	$668,158	$373,507	$2,846,655
	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	681,830	699,345	722,731	751,839	782,759	826,352	889,266	915,766	1,442,766	1,962,511	2,486,820	3,154,978	3,528,485	
5.	Net Investment (Lines 2 + 3 + 4)	$681,830	$699,345	$722,731	$751,839	$782,759	$826,352	$889,266	$915,766	$1,442,766	$1,962,511	$2,486,820	$3,154,978	$3,528,485	
6.	Average Net Investment		690,588	711,038	737,285	767,299	804,555	857,809	902,516	1,179,266	1,702,638	2,224,665	2,820,899	3,341,731	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,432	$3,534	$3,664	$3,813	$3,998	$4,263	$4,520	$5,906	$8,527	$11,141	$14,127	$16,735	$83,660
	b. Debt Component Grossed Up For Taxes (C)		1,000	1,029	1,067	1,111	1,165	1,242	1,348	1,762	2,543	3,323	4,214	4,992	24,796
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,432	4,563	4,731	4,924	5,163	5,505	5,868	7,668	11,070	14,464	18,341	21,727	108,456
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,432	4,563	4,731	4,924	5,163	5,505	5,868	7,668	11,070	14,464	18,341	21,727	108,456
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,432	4,563	4,731	4,924	5,163	5,505	5,868	7,668	11,070	14,464	18,341	21,727	108,456
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,432	$4,563	$4,731	$4,924	$5,163	$5,505	$5,868	$7,668	$11,070	$14,464	$18,341	$21,727	$108,456

Notes:

(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

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

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$3,416	$4,038	$22,491	$20,109	$23,361	$24,716	$259,481	$578,593	$578,593	$791,334	$791,605	$1,023,805	$4,121,542
	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	139,594	143,010	147,048	169,538	189,648	213,009	237,725	497,206	1,075,799	1,654,392	2,445,726	3,237,331	4,261,136	
5.	Net Investment (Lines 2 + 3 + 4)	$139,594	$143,010	$147,048	$169,538	$189,648	$213,009	$237,725	$497,206	$1,075,799	$1,654,392	$2,445,726	$3,237,331	$4,261,136	
6.	Average Net Investment		141,302	145,029	158,293	179,593	201,328	225,367	367,465	786,502	1,365,095	2,050,059	2,841,528	3,749,233	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$702	$721	$787	$893	$1,001	$1,120	$1,840	$3,939	$6,836	$10,267	$14,230	$18,776	$61,112
	b. Debt Component Grossed Up For Taxes (C)		205	210	229	260	291	326	549	1,175	2,039	3,062	4,245	5,601	18,192
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		907	931	1,016	1,153	1,292	1,446	2,389	5,114	8,875	13,329	18,475	24,377	79,304
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		907	931	1,016	1,153	1,292	1,446	2,389	5,114	8,875	13,329	18,475	24,377	79,304
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		907	931	1,016	1,153	1,292	1,446	2,389	5,114	8,875	13,329	18,475	24,377	79,304
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$907	$931	$1,016	$1,153	$1,292	$1,446	$2,389	$5,114	$8,875	$13,329	$18,475	$24,377	$79,304

Notes:

(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2020 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. MAS-2, DOCUMENT NO. 8,
PAGE 28 OF 29

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Sec. 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$3,886	$7,498	$81,696	$22,094	$22,934	$81,636	$28,000	$79,000	$468,094	$31,000	$58,000	$107,991	$991,829
	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	59,601	63,487	70,985	152,681	174,776	197,709	279,345	307,345	386,345	854,439	885,439	943,439	1,051,430	
5.	Net Investment (Lines 2 + 3 + 4)	$59,601	$63,487	$70,985	$152,681	$174,776	$197,709	$279,345	$307,345	$386,345	$854,439	$885,439	$943,439	$1,051,430	
6.	Average Net Investment		61,544	67,236	111,833	163,728	186,242	238,527	293,345	346,845	620,392	869,939	914,439	997,435	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$306	$334	$556	$814	$926	$1,185	$1,469	$1,737	$3,107	$4,357	$4,580	$4,995	$24,366
	b. Debt Component Grossed Up For Taxes (C)		89	97	162	237	270	345	438	518	927	1,300	1,366	1,490	7,239
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		395	431	718	1,051	1,196	1,530	1,907	2,255	4,034	5,657	5,946	6,485	31,605
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		395	431	718	1,051	1,196	1,530	1,907	2,255	4,034	5,657	5,946	6,485	31,605
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		395	431	718	1,051	1,196	1,530	1,907	2,255	4,034	5,657	5,946	6,485	31,605
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$395	$431	$718	$1,051	$1,196	$1,530	$1,907	$2,255	$4,034	$5,657	$5,946	$6,485	$31,605

Notes:

(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2020 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. MAS-2, DOCUMENT NO. 8,
PAGE 29 OF 29

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
January 2020 to June 2020

Form 42 - 9E
Page 1 of 2

Calculation of Revenue Requirement Rate of Return
(in Dollars)

	(1) Jurisdictional Rate Base **Actual May 2019** ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,897,597	31.57%	4.89%	1.5435%
Short Term Debt	211,895	3.52%	2.97%	0.1047%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	94,966	1.58%	2.38%	0.0376%
Common Equity	2,598,065	43.22%	10.25%	4.4297%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,125,550	18.72%	0.00%	0.0000%
Deferred ITC - Weighted Cost	83,633	1.39%	7.98%	0.1110%
Total	$ 6,011,707	100.00%		6.23%

ITC split between Debt and Equity:

Long Term Debt	$ 1,897,597	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,598,065	Equity - Common	54.00%
Total	$ 4,495,662	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	0.0599%
Weighted Cost	0.1110%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	0.0599%
	4.4896%
Times Tax Multiplier	1.32830
Total Equity Component	5.9635%

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	0.0511%
Total Debt Component	1.7369%
	7.7004%

Notes:

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

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of the Current Period Actual / Estimated Amount
July 2020 to December 2020

Form 42 - 9E
Page 2 of 2

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base **Actual May 2020** ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 2,209,385	33.98%	4.71%	1.6003%
Short Term Debt	196,185	3.02%	2.19%	0.0661%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	93,706	1.44%	2.36%	0.0340%
Common Equity	2,801,776	43.08%	10.25%	4.4160%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,034,859	15.91%	0.00%	0.0000%
Deferred ITC - Weighted Cost	166,903	2.57%	7.81%	0.2005%
Total	$ 6,502,815	100.00%		6.32%

ITC split between Debt and Equity:

Long Term Debt	$ 2,209,385	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,801,776	Equity - Common	54.00%
Total	$ 5,011,162	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.2005% * 46.00%	0.0922%
Equity = 0.2005% * 54.00%	0.1083%
Weighted Cost	0.2005%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4160%
Deferred ITC - Weighted Cost	0.1083%
	4.5243%
Times Tax Multiplier	1.32830
Total Equity Component	6.0096%

Total Debt Cost Rate:

Long Term Debt	1.6003%
Short Term Debt	0.0661%
Customer Deposits	0.0340%
Deferred ITC - Weighted Cost	0.0922%
Total Debt Component	1.7926%
	7.8022%

Notes:

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

DOCKET NO. 20200007-EI
ECRC 2021 PROJECTION
EXHIBIT NO. MAS-3

EXHIBIT TO THE TESTIMONY OF
M. ASHLEY SIZEMORE

TAMPA ELECTRIC'S ENVIRONMENTAL
COST RECOVERY

PROJECTION

JANUARY 2021 THROUGH DECEMBER 2021

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 34
PARTY: MAS-3
DESCRIPTION: Environmental Cost Recovery Commission Forms 42-1P through 42-8P Forms for the Period January 2021 t...

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ENVIRONMENTAL COST RECOVERY

COMMISSION FORMS

JANUARY 2021 THROUGH DECEMBER 2021

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4	Form 42-4P	18
5	Form 42-5P	47
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7	Form 42-7P	82
8	Form 42-8P	83

Tampa Electric Company Form 42 - 1P

Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2021 to December 2021

Line	Energy ($)	Demand ($)	Total ($)
1. Total Jurisdictional Revenue Requirements for the projected period			
a. Projected O&M Activities (Form 42-2P, Lines 7, 8 & 9)	$3,375,618	$104,500	$3,480,118
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	42,617,540	2,095,248	44,712,788
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	45,993,158	2,199,748	48,192,906
2. True-up for Estimated Over/(Under) Recovery for the current period January 2020 to December 2020 (Form 42-2E, Line 5 + 6 + 10)	(7,759,917)	(81,259)	(7,841,176)
3. Final True-up for the period January 2019 to December 2019 (Form 42-1A, Line 3)	3,955,082	32,833	3,987,915
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2021 to December 2021 (Line 1 - Line 2- Line 3)	49,797,993	2,248,174	52,046,167
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$49,833,848	$2,249,793	$52,083,641

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

O&M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 FGD Integration	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(4)	4	4	(4)	4	4	(4)	4	4	(4)	4	4	15		15
	d. Big Bend Units 1 & 2 FGD	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	e. Big Bend PM Minimization and Monitoring	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	252,000		252,000
	f. Big Bend NO_x Emissions Reduction	169	169	169	169	169	169	169	169	169	169	169	169	2,028		2,028
	g. NPDES Annual Surveillance Fees	23,500	0	0	0	0	0	0	0	0	0	0	0	23,500	$23,500	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	i. Polk NO_x Emissions Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	j. Bayside SCR and Ammonia	8,000	8,000	9,000	10,000	11,000	12,000	12,000	12,000	11,000	10,000	8,000	8,000	119,000		119,000
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	o. Clean Water Act Section 316(b) Phase II Study	5,000	15,000	0	20,000	2,500	2,500	0	0	0	0	0	0	45,000	45,000	
	p. Arsenic Groundwater Standard Program	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000	36,000	
	q. Big Bend Unit 1 SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	r. Big Bend Unit 2 SCR	8,069	3,999	13,404	11,861	14,428	8,846	11,380	11,029	12,342	26,662	0	0	122,020		122,020
	s. Big Bend Unit 3 SCR	26,583	20,671	51,107	43,282	32,923	39,624	36,347	33,343	33,017	36,233	95,432	75,535	524,097		524,097
	t. Big Bend Unit 4 SCR	109,044	119,025	79,185	88,553	96,344	95,226	95,969	99,324	98,337	80,801	47,763	67,661	1,077,230		1,077,230
	u. Mercury Air Toxics Standards	0	0	3,000	0	0	0	0	0	0	0	0	0	3,000		3,000
	v. Greenhouse Gas Reduction Program	0	0	53,528	0	40,000	0	0	0	0	0	0	0	93,528		93,528
	w. Big Bend Gypsum Storage Facility (East 40)	98,158	98,158	98,158	98,158	98,158	98,158	98,158	98,158	98,158	98,158	98,158	98,158	1,177,899		1,177,899
	x. Big Bend CCR Rule - Phase I	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	y. Big Bend ELG Compliance	400	400	400	400	400	400	400	400	400	400	400	400	4,800		4,800
	z. Big Bend CCR Rule - Phase II	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	aa. Big Bend Unit 1 Sec. 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	302,918	289,427	331,955	296,418	319,927	280,927	278,418	278,427	277,427	276,418	273,927	273,927	3,480,118	$104,500	$3,375,618
3.	Recoverable Costs Allocated to Energy	271,418	271,427	328,955	273,418	314,427	275,427	275,418	275,427	274,427	273,418	270,927	270,927	3,375,618		
4.	Recoverable Costs Allocated to Demand	31,500	18,000	3,000	23,000	5,500	5,500	3,000	3,000	3,000	3,000	3,000	3,000	104,500		
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)	271,418	271,427	328,955	273,418	314,427	275,428	275,418	275,427	274,427	273,418	270,927	270,928	3,375,618		
8.	Jurisdictional Demand Recoverable Costs (B)	31,500	18,000	3,000	23,000	5,500	5,500	3,000	3,000	3,000	3,000	3,000	3,000	104,500		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$302,918	$289,427	$331,955	$296,418	$319,927	$280,928	$278,418	$278,427	$277,427	$276,418	$273,927	$273,928	$3,480,118		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

DOCKET NO. 20200007-EI
ECRC 2021 PROJECTION, FORM 42-2P
EXHIBIT NO. MAS-3 , DOCUMENT NO. 2

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Form 42-3P

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description (A)		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 FGD Integration	1	$76,549	$76,359	$76,171	$75,981	$75,791	$75,603	$75,413	$75,224	$75,035	$74,845	$74,657	$74,467	$906,095		$906,095
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	17,777	17,671	17,565	17,459	17,354	17,247	17,142	17,036	16,929	16,824	12,289	7,749	193,042		193,042
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	3,883	3,868	3,853	3,838	3,823	3,807	3,792	3,777	3,762	3,747	3,732	3,716	45,598		45,598
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4	5,510	5,476	5,442	5,409	5,375	5,341	5,308	5,274	5,241	5,207	5,173	5,140	63,896	$63,896	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	5	9,062	9,007	8,952	8,896	8,841	8,785	8,730	8,675	8,620	8,564	8,509	8,457	105,098	105,098	
	f.	Big Bend Unit 1 Classifier Replacement	6	5,925	5,897	5,867	5,839	5,810	5,781	5,752	5,724	5,694	5,666	5,638	5,608	69,201		69,201
	g.	Big Bend Unit 2 Classifier Replacement	7	4,317	4,296	4,277	4,256	4,237	4,217	4,197	4,177	4,157	4,137	4,117	4,097	50,482		50,482
	h.	Big Bend Section 114 Mercury Testing Platform	8	674	672	670	668	666	664	662	660	659	656	655	652	7,958		7,958
	i.	Big Bend Units 1 & 2 FGD	9	462,864	461,146	459,427	457,708	455,989	454,270	452,552	450,833	449,114	447,395	445,676	443,957	5,440,931		5,440,931
	j.	Big Bend FGD Optimization and Utilization	10	127,323	127,010	126,697	126,385	126,072	125,759	125,446	125,134	124,821	124,508	124,195	123,883	1,507,233		1,507,233
	k.	Big Bend NO_x Emissions Reduction	11	40,969	40,902	40,835	40,769	40,701	40,634	40,567	40,501	40,434	40,367	40,301	40,234	487,214		487,214
	l.	Big Bend PM Minimization and Monitoring	12	142,586	142,188	141,788	141,388	140,989	140,589	140,190	139,790	139,391	138,992	138,592	138,192	1,684,675		1,684,675
	m.	Polk NO_x Emissions Reduction	13	8,779	8,749	8,721	8,691	8,662	8,634	8,604	8,576	8,547	8,517	8,489	8,459	103,428		103,428
	n.	Big Bend Unit 4 SOFA	14	15,688	15,646	15,604	15,562	15,520	15,478	15,436	15,395	15,352	15,310	15,268	15,227	185,486		185,486
	o.	Big Bend Unit 1 Pre-SCR	15	10,635	10,598	10,562	10,526	10,490	10,454	10,418	10,382	10,345	10,309	10,273	10,237	125,229		125,229
	p.	Big Bend Unit 2 Pre-SCR	16	10,189	10,157	10,125	10,093	10,061	10,029	9,998	9,966	9,934	9,902	9,870	9,838	120,162		120,162
	q.	Big Bend Unit 3 Pre-SCR	17	18,348	18,295	18,244	18,191	18,139	18,086	18,035	17,983	17,930	17,879	17,826	17,774	216,730		216,730
	r.	Big Bend Unit 1 SCR	18	608,310	606,281	604,252	602,222	600,194	598,165	596,136	594,108	592,079	590,049	588,021	585,992	7,165,809		7,165,809
	s.	Big Bend Unit 2 SCR	19	669,093	667,044	664,994	662,944	660,894	658,843	656,794	654,744	652,694	650,644	648,595	646,545	7,893,828		7,893,828
	t.	Big Bend Unit 3 SCR	20	544,920	543,265	541,611	539,957	538,303	536,648	534,994	533,341	531,686	530,032	528,377	526,723	6,429,857		6,429,857
	u.	Big Bend Unit 4 SCR	21	437,462	436,198	434,936	433,837	433,147	432,541	431,688	431,409	432,993	433,024	432,009	430,732	5,199,976		5,199,976
	v.	Big Bend FGD System Reliability	22	169,626	169,288	168,950	168,611	168,273	167,934	167,595	167,256	166,918	166,579	166,241	165,903	2,013,174		2,013,174
	w.	Mercury Air Toxics Standards	23	66,057	65,911	65,765	65,619	65,473	65,327	65,180	65,033	64,887	64,741	64,595	64,448	783,036		783,036
	x.	SO_2 Emissions Allowances (B)	24	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(2,688)		(2,688)
	y.	Big Bend Gypsum Storage Facility	25	167,796	167,456	167,115	166,775	166,434	166,094	165,753	165,413	165,073	164,732	164,392	164,051	1,991,084		1,991,084
	z.	Big Bend CCR Rule - Phase I	26	22,963	25,605	29,102	30,090	30,316	30,304	30,282	30,254	30,225	30,195	36,835	36,762	362,933	362,933	
	aa.	Big Bend CCR Rule - Phase II	27	23,582	24,287	25,091	25,752	26,008	26,157	26,199	26,232	26,248	26,248	36,216	36,149	328,169	328,169	
	ab.	Big Bend ELG Compliance	28	30,885	35,485	40,073	45,901	51,728	58,124	65,768	74,237	82,619	90,893	99,225	107,712	782,650	782,650	
	ac.	Big Bend Unit 1 Sec. 316(b) Impingement Mortality	29	8,442	11,468	15,484	20,153	24,648	29,845	35,834	42,592	54,434	65,361	70,254	73,987	452,502	452,502	
2.		Total Investment Projects - Recoverable Costs		3,709,990	3,710,001	3,711,949	3,713,296	3,713,714	3,715,136	3,718,241	3,723,502	3,735,597	3,745,099	3,759,796	3,756,467	44,712,788	$2,095,248	$42,617,540
3.		Recoverable Costs Allocated to Energy		3,609,546	3,598,673	3,587,805	3,577,095	3,566,798	3,556,580	3,546,120	3,536,238	3,528,210	3,518,631	3,503,584	3,488,260	42,617,540		42,617,540
4.		Recoverable Costs Allocated to Demand		100,444	111,328	124,144	136,201	146,916	158,556	172,121	187,264	207,387	226,468	256,212	268,207	2,095,248	2,095,248	
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)		3,609,546	3,598,673	3,587,805	3,577,095	3,566,798	3,556,580	3,546,120	3,536,238	3,528,210	3,518,631	3,503,584	3,488,260	42,617,540		
8.		Jurisdictional Demand Recoverable Costs (D)		100,444	111,328	124,144	136,201	146,916	158,556	172,121	187,264	207,387	226,468	256,212	268,207	2,095,248		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$3,709,990	$3,710,001	$3,711,949	$3,713,296	$3,713,714	$3,715,136	$3,718,241	$3,723,502	$3,735,597	$3,745,099	$3,759,796	$3,756,467	$44,712,788		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9
(B) Project's Total Return Component on Form 42-4P, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

DOCKET NO. 20200007-EI
ECRC 2021 PROJECTION, FORM 42-3P
EXHIBIT NO. MAS-3 , DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 FGD Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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)	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	$13,763,263	
3.	Less: Accumulated Depreciation	(6,478,449)	(6,507,287)	(6,536,125)	(6,564,963)	(6,593,801)	(6,622,639)	(6,651,477)	(6,680,315)	(6,709,153)	(6,737,991)	(6,766,829)	(6,795,667)	(6,824,505)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,284,814	7,255,976	7,227,138	7,198,300	7,169,462	7,140,624	7,111,786	7,082,948	7,054,110	7,025,272	6,996,434	6,967,596	6,938,758	
6.	Average Net Investment		7,270,395	7,241,557	7,212,719	7,183,881	7,155,043	7,126,205	7,097,367	7,068,529	7,039,691	7,010,853	6,982,015	6,953,177	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$37,219	$37,071	$36,924	$36,776	$36,628	$36,481	$36,333	$36,186	$36,038	$35,890	$35,743	$35,595	$436,884
	b. Debt Component Grossed Up For Taxes (C)		10,492	10,450	10,409	10,367	10,325	10,284	10,242	10,200	10,159	10,117	10,076	10,034	123,155
8.	Investment Expenses														
	a. Depreciation (D)		28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	28,838	346,056
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		76,549	76,359	76,171	75,981	75,791	75,603	75,413	75,224	75,035	74,845	74,657	74,467	906,095
	a. Recoverable Costs Allocated to Energy		76,549	76,359	76,171	75,981	75,791	75,603	75,413	75,224	75,035	74,845	74,657	74,467	906,095
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		76,549	76,359	76,171	75,981	75,791	75,603	75,413	75,224	75,035	74,845	74,657	74,467	906,095
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$76,549	$76,359	$76,171	$75,981	$75,791	$75,603	$75,413	$75,224	$75,035	$74,845	$74,657	$74,467	$906,095

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775), 315.45 ($327,307), and 312.40 ($182).
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rates are 2.5%, 3.1%, and 3.4%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2021 PROJECTION, FORM 42-4P
EXHIBIT NO. MAS-3, DOCUMENT NO. 4, PAGE 1 OF 29

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(4,760,354)	(4,776,495)	(4,792,636)	(4,808,777)	(4,824,918)	(4,841,059)	(4,857,200)	(4,873,341)	(4,889,482)	(4,905,623)	(4,921,764)	(4,933,462)	(4,940,682)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$257,380	241,239	225,098	208,957	192,816	176,675	160,534	144,393	128,252	112,111	95,970	84,272	77,052	
6.	Average Net Investment		249,310	233,169	217,028	200,887	184,746	168,605	152,464	136,323	120,182	104,041	90,121	80,662	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,276	$1,194	$1,111	$1,028	$946	$863	$781	$698	$615	$533	$461	$413	$9,919
	b. Debt Component Grossed Up For Taxes (C)		360	336	313	290	267	243	220	197	173	150	130	116	2,795
8.	Investment Expenses														
	a. Depreciation (D)		16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	16,141	11,698	7,220	180,328
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,777	17,671	17,565	17,459	17,354	17,247	17,142	17,036	16,929	16,824	12,289	7,749	193,042
	a. Recoverable Costs Allocated to Energy		17,777	17,671	17,565	17,459	17,354	17,247	17,142	17,036	16,929	16,824	12,289	7,749	193,042
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		17,777	17,671	17,565	17,459	17,354	17,247	17,142	17,036	16,929	16,824	12,289	7,749	193,042
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,777	$17,671	$17,565	$17,459	$17,354	$17,247	$17,142	$17,036	$16,929	$16,824	$12,289	$7,749	$193,042

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rates are 4.0% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(625,325)	(627,635)	(629,945)	(632,255)	(634,565)	(636,875)	(639,185)	(641,495)	(643,805)	(646,115)	(648,425)	(650,735)	(653,045)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$240,886	238,576	236,266	233,956	231,646	229,336	227,026	224,716	222,406	220,096	217,786	215,476	213,166	
6.	Average Net Investment		239,731	237,421	235,111	232,801	230,491	228,181	225,871	223,561	221,251	218,941	216,631	214,321	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,227	$1,215	$1,204	$1,192	$1,180	$1,168	$1,156	$1,144	$1,133	$1,121	$1,109	$1,097	$13,946
	b. Debt Component Grossed Up For Taxes (C)		346	343	339	336	333	329	326	323	319	316	313	309	3,932
8.	Investment Expenses														
	a. Depreciation (D)		2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	2,310	27,720
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		3,883	3,868	3,853	3,838	3,823	3,807	3,792	3,777	3,762	3,747	3,732	3,716	45,598
	a. Recoverable Costs Allocated to Energy		3,883	3,868	3,853	3,838	3,823	3,807	3,792	3,777	3,762	3,747	3,732	3,716	45,598
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		3,883	3,868	3,853	3,838	3,823	3,807	3,792	3,777	3,762	3,747	3,732	3,716	45,598
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$3,883	$3,868	$3,853	$3,838	$3,823	$3,807	$3,792	$3,777	$3,762	$3,747	$3,732	$3,716	$45,598

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2021 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(436,102)	(441,225)	(446,348)	(451,471)	(456,594)	(461,717)	(466,840)	(471,963)	(477,086)	(482,209)	(487,332)	(492,455)	(497,578)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$61,476	56,353	51,230	46,107	40,984	35,861	30,738	25,615	20,492	15,369	10,246	5,123	0	
6.	Average Net Investment		58,915	53,792	48,669	43,546	38,423	33,300	28,177	23,054	17,931	12,808	7,685	2,562	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$302	$275	$249	$223	$197	$170	$144	$118	$92	$66	$39	$13	$1,888
	b. Debt Component Grossed Up For Taxes (C)		85	78	70	63	55	48	41	33	26	18	11	4	532
8.	Investment Expenses														
	a. Depreciation (D)		5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,476
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		5,510	5,476	5,442	5,409	5,375	5,341	5,308	5,274	5,241	5,207	5,173	5,140	63,896
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		5,510	5,476	5,442	5,409	5,375	5,341	5,308	5,274	5,241	5,207	5,173	5,140	63,896
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		5,510	5,476	5,442	5,409	5,375	5,341	5,308	5,274	5,241	5,207	5,173	5,140	63,896
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,510	$5,476	$5,442	$5,409	$5,375	$5,341	$5,308	$5,274	$5,241	$5,207	$5,173	$5,140	$63,896

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2021 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(717,286)	(725,712)	(734,138)	(742,564)	(750,990)	(759,416)	(767,842)	(776,268)	(784,694)	(793,120)	(801,546)	(809,972)	(818,401)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$101,115	92,689	84,263	75,837	67,411	58,985	50,559	42,133	33,707	25,281	16,855	8,429	0	
6.	Average Net Investment		96,902	88,476	80,050	71,624	63,198	54,772	46,346	37,920	29,494	21,068	12,642	4,215	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$496	$453	$410	$367	$324	$280	$237	$194	$151	$108	$65	$22	$3,107
	b. Debt Component Grossed Up For Taxes (C)		140	128	116	103	91	79	67	55	43	30	18	6	876
8.	Investment Expenses														
	a. Depreciation (D)		8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,426	8,429	101,115
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,062	9,007	8,952	8,896	8,841	8,785	8,730	8,675	8,620	8,564	8,509	8,457	105,098
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		9,062	9,007	8,952	8,896	8,841	8,785	8,730	8,675	8,620	8,564	8,509	8,457	105,098
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		9,062	9,007	8,952	8,896	8,841	8,785	8,730	8,675	8,620	8,564	8,509	8,457	105,098
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,062	$9,007	$8,952	$8,896	$8,841	$8,785	$8,730	$8,675	$8,620	$8,564	$8,509	$8,457	$105,098

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 12.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(1,079,816)	(1,084,204)	(1,088,592)	(1,092,980)	(1,097,368)	(1,101,756)	(1,106,144)	(1,110,532)	(1,114,920)	(1,119,308)	(1,123,696)	(1,128,084)	(1,132,472)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$236,441	232,053	227,665	223,277	218,889	214,501	210,113	205,725	201,337	196,949	192,561	188,173	183,785	
6.	Average Net Investment		234,247	229,859	225,471	221,083	216,695	212,307	207,919	203,531	199,143	194,755	190,367	185,979	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,199	$1,177	$1,154	$1,132	$1,109	$1,087	$1,064	$1,042	$1,019	$997	$975	$952	$12,907
	b. Debt Component Grossed Up For Taxes (C)		338	332	325	319	313	306	300	294	287	281	275	268	3,638
8.	Investment Expenses														
	a. Depreciation (D)		4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	4,388	52,656
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		5,925	5,897	5,867	5,839	5,810	5,781	5,752	5,724	5,694	5,666	5,638	5,608	69,201
	a. Recoverable Costs Allocated to Energy		5,925	5,897	5,867	5,839	5,810	5,781	5,752	5,724	5,694	5,666	5,638	5,608	69,201
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		5,925	5,897	5,867	5,839	5,810	5,781	5,752	5,724	5,694	5,666	5,638	5,608	69,201
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,925	$5,897	$5,867	$5,839	$5,810	$5,781	$5,752	$5,724	$5,694	$5,666	$5,638	$5,608	$69,201

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(788,166)	(791,202)	(794,238)	(797,274)	(800,310)	(803,346)	(806,382)	(809,418)	(812,454)	(815,490)	(818,526)	(821,562)	(824,598)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$196,628	193,592	190,556	187,520	184,484	181,448	178,412	175,376	172,340	169,304	166,268	163,232	160,196	
6.	Average Net Investment		195,110	192,074	189,038	186,002	182,966	179,930	176,894	173,858	170,822	167,786	164,750	161,714	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$999	$983	$968	$952	$937	$921	$906	$890	$874	$859	$843	$828	$10,960
	b. Debt Component Grossed Up For Taxes (C)		282	277	273	268	264	260	255	251	247	242	238	233	3,090
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)		4,317	4,296	4,277	4,256	4,237	4,217	4,197	4,177	4,157	4,137	4,117	4,097	50,482
	a. Recoverable Costs Allocated to Energy		4,317	4,296	4,277	4,256	4,237	4,217	4,197	4,177	4,157	4,137	4,117	4,097	50,482
	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)		4,317	4,296	4,277	4,256	4,237	4,217	4,197	4,177	4,157	4,137	4,117	4,097	50,482
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)		$4,317	$4,296	$4,277	$4,256	$4,237	$4,217	$4,197	$4,177	$4,157	$4,137	$4,117	$4,097	$50,482

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(62,419)	(62,711)	(63,003)	(63,295)	(63,587)	(63,879)	(64,171)	(64,463)	(64,755)	(65,047)	(65,339)	(65,631)	(65,923)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$58,318	58,026	57,734	57,442	57,150	56,858	56,566	56,274	55,982	55,690	55,398	55,106	54,814	
6.	Average Net Investment		58,172	57,880	57,588	57,296	57,004	56,712	56,420	56,128	55,836	55,544	55,252	54,960	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$298	$296	$295	$293	$292	$290	$289	$287	$286	$284	$283	$281	$3,474
	b. Debt Component Grossed Up For Taxes (C)		84	84	83	83	82	82	81	81	81	80	80	79	980
8.	Investment Expenses														
	a. Depreciation (D)		292	292	292	292	292	292	292	292	292	292	292	292	3,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		674	672	670	668	666	664	662	660	659	656	655	652	7,958
	a. Recoverable Costs Allocated to Energy		674	672	670	668	666	664	662	660	659	656	655	652	7,958
	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	672	670	668	666	664	662	660	659	656	655	652	7,958
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	$672	$670	$668	$666	$664	$662	$660	$659	$656	$655	$652	$7,958

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(64,503,293)	(64,765,212)	(65,027,131)	(65,289,050)	(65,550,969)	(65,812,888)	(66,074,807)	(66,336,726)	(66,598,645)	(66,860,564)	(67,122,483)	(67,384,402)	(67,646,321)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$30,751,949	30,490,030	30,228,111	29,966,192	29,704,273	29,442,354	29,180,435	28,918,516	28,656,597	28,394,678	28,132,759	27,870,840	27,608,921	
6.	Average Net Investment		30,620,989	30,359,070	30,097,151	29,835,232	29,573,313	29,311,394	29,049,475	28,787,556	28,525,637	28,263,718	28,001,799	27,739,880	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$156,756	$155,416	$154,075	$152,734	$151,393	$150,052	$148,712	$147,371	$146,030	$144,689	$143,348	$142,007	$1,792,583
	b. Debt Component Grossed Up For Taxes (C)		44,189	43,811	43,433	43,055	42,677	42,299	41,921	41,543	41,165	40,787	40,409	40,031	505,320
8.	Investment Expenses														
	a. Depreciation (D)		261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	261,919	3,143,028
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		462,864	461,146	459,427	457,708	455,989	454,270	452,552	450,833	449,114	447,395	445,676	443,957	5,440,931
	a. Recoverable Costs Allocated to Energy		462,864	461,146	459,427	457,708	455,989	454,270	452,552	450,833	449,114	447,395	445,676	443,957	5,440,931
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		462,864	461,146	459,427	457,708	455,989	454,270	452,552	450,833	449,114	447,395	445,676	443,957	5,440,931
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$462,864	$461,146	$459,427	$457,708	$455,989	$454,270	$452,552	$450,833	$449,114	$447,395	$445,676	$443,957	$5,440,931

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.46 ($94,929,061), 312.45 ($105,398), and 315.46 ($220,782)
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rates are 3.3%, 2.5%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2021 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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)	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	$22,653,929	
3.	Less: Accumulated Depreciation	(10,488,770)	(10,536,417)	(10,584,064)	(10,631,711)	(10,679,358)	(10,727,005)	(10,774,652)	(10,822,299)	(10,869,946)	(10,917,593)	(10,965,240)	(11,012,887)	(11,060,534)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$12,165,159	12,117,512	12,069,865	12,022,218	11,974,571	11,926,924	11,879,277	11,831,630	11,783,983	11,736,336	11,688,689	11,641,042	11,593,395	
6.	Average Net Investment		12,141,336	12,093,689	12,046,042	11,998,395	11,950,748	11,903,101	11,855,454	11,807,807	11,760,160	11,712,513	11,664,866	11,617,219	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$62,155	$61,911	$61,667	$61,423	$61,179	$60,935	$60,691	$60,447	$60,203	$59,959	$59,715	$59,471	$729,756
	b. Debt Component Grossed Up For Taxes (C)		17,521	17,452	17,383	17,315	17,246	17,177	17,108	17,040	16,971	16,902	16,833	16,765	205,713
8.	Investment Expenses														
	a. Depreciation (D)		47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	47,647	571,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		127,323	127,010	126,697	126,385	126,072	125,759	125,446	125,134	124,821	124,508	124,195	123,883	1,507,233
	a. Recoverable Costs Allocated to Energy		127,323	127,010	126,697	126,385	126,072	125,759	125,446	125,134	124,821	124,508	124,195	123,883	1,507,233
	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)		127,323	127,010	126,697	126,385	126,072	125,759	125,446	125,134	124,821	124,508	124,195	123,883	1,507,233
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)		$127,323	$127,010	$126,697	$126,385	$126,072	$125,759	$125,446	$125,134	$124,821	$124,508	$124,195	$123,883	$1,507,233

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,855,886), 311.45 ($40,016), 316.40 ($71,401), 315.45 ($594,901), 312.42 ($1,637), and 312.40 ($90,088)
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rates are 2.5%, 2.0%, 4.2%, 3.1%, 3.7%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2021 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	1,505,355	1,495,171	1,484,987	1,474,803	1,464,619	1,454,435	1,444,251	1,434,067	1,423,883	1,413,699	1,403,515	1,393,331	1,383,147	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,696,207	4,686,023	4,675,839	4,665,655	4,655,471	4,645,287	4,635,103	4,624,919	4,614,735	4,604,551	4,594,367	4,584,183	4,573,999	
6.	Average Net Investment		4,691,115	4,680,931	4,670,747	4,660,563	4,650,379	4,640,195	4,630,011	4,619,827	4,609,643	4,599,459	4,589,275	4,579,091	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$24,015	$23,963	$23,911	$23,859	$23,806	$23,754	$23,702	$23,650	$23,598	$23,546	$23,494	$23,442	$284,740
	b. Debt Component Grossed Up For Taxes (C)		6,770	6,755	6,740	6,726	6,711	6,696	6,681	6,667	6,652	6,637	6,623	6,608	80,266
8.	Investment Expenses														
	a. Depreciation (D)		10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		40,969	40,902	40,835	40,769	40,701	40,634	40,567	40,501	40,434	40,367	40,301	40,234	487,214
	a. Recoverable Costs Allocated to Energy		40,969	40,902	40,835	40,769	40,701	40,634	40,567	40,501	40,434	40,367	40,301	40,234	487,214
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		40,969	40,902	40,835	40,769	40,701	40,634	40,567	40,501	40,434	40,367	40,301	40,234	487,214
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$40,969	$40,902	$40,835	$40,769	$40,701	$40,634	$40,567	$40,501	$40,434	$40,367	$40,301	$40,234	$487,214

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rates are 4.0%, 3.7%, and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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)	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	
3.	Less: Accumulated Depreciation	(7,275,250)	(7,336,122)	(7,396,994)	(7,457,866)	(7,518,738)	(7,579,610)	(7,640,482)	(7,701,354)	(7,762,226)	(7,823,098)	(7,883,970)	(7,944,842)	(8,005,714)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$12,482,500	12,421,628	12,360,756	12,299,884	12,239,012	12,178,140	12,117,268	12,056,396	11,995,524	11,934,652	11,873,780	11,812,908	11,752,036	
6.	Average Net Investment		12,452,064	12,391,192	12,330,320	12,269,448	12,208,576	12,147,704	12,086,832	12,025,960	11,965,088	11,904,216	11,843,344	11,782,472	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$63,745	$63,434	$63,122	$62,810	$62,499	$62,187	$61,876	$61,564	$61,252	$60,941	$60,629	$60,317	$744,376
	b. Debt Component Grossed Up For Taxes (C)		17,969	17,882	17,794	17,706	17,618	17,530	17,442	17,354	17,267	17,179	17,091	17,003	209,835
8.	Investment Expenses														
	a. Depreciation (D)		60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	60,872	730,464
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		142,586	142,188	141,788	141,388	140,989	140,589	140,190	139,790	139,391	138,992	138,592	138,192	1,684,675
	a. Recoverable Costs Allocated to Energy		142,586	142,188	141,788	141,388	140,989	140,589	140,190	139,790	139,391	138,992	138,592	138,192	1,684,675
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		142,586	142,188	141,788	141,388	140,989	140,589	140,190	139,790	139,391	138,992	138,592	138,192	1,684,675
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$142,586	$142,188	$141,788	$141,388	$140,989	$140,589	$140,190	$139,790	$139,391	$138,992	$138,592	$138,192	$1,684,675

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($5,831,465), 312.42 ($5,153,072), 312.43 ($7,875,560), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554)
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(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 (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(895,674)	(900,098)	(904,522)	(908,946)	(913,370)	(917,794)	(922,218)	(926,642)	(931,066)	(935,490)	(939,914)	(944,338)	(948,762)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$665,799	661,375	656,951	652,527	648,103	643,679	639,255	634,831	630,407	625,983	621,559	617,135	612,711	
6.	Average Net Investment		663,587	659,163	654,739	650,315	645,891	641,467	637,043	632,619	628,195	623,771	619,347	614,923	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,397	$3,374	$3,352	$3,329	$3,306	$3,284	$3,261	$3,239	$3,216	$3,193	$3,171	$3,148	$39,270
	b. Debt Component Grossed Up For Taxes (C)		958	951	945	938	932	926	919	913	907	900	894	887	11,070
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,779	8,749	8,721	8,691	8,662	8,634	8,604	8,576	8,547	8,517	8,489	8,459	103,428
	a. Recoverable Costs Allocated to Energy		8,779	8,749	8,721	8,691	8,662	8,634	8,604	8,576	8,547	8,517	8,489	8,459	103,428
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		8,779	8,749	8,721	8,691	8,662	8,634	8,604	8,576	8,547	8,517	8,489	8,459	103,428
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,779	$8,749	$8,721	$8,691	$8,662	$8,634	$8,604	$8,576	$8,547	$8,517	$8,489	$8,459	$103,428

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(1,139,726)	(1,146,123)	(1,152,520)	(1,158,917)	(1,165,314)	(1,171,711)	(1,178,108)	(1,184,505)	(1,190,902)	(1,197,299)	(1,203,696)	(1,210,093)	(1,216,490)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,419,004	1,412,607	1,406,210	1,399,813	1,393,416	1,387,019	1,380,622	1,374,225	1,367,828	1,361,431	1,355,034	1,348,637	1,342,240	
6.	Average Net Investment		1,415,806	1,409,409	1,403,012	1,396,615	1,390,218	1,383,821	1,377,424	1,371,027	1,364,630	1,358,233	1,351,836	1,345,439	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,248	$7,215	$7,182	$7,150	$7,117	$7,084	$7,051	$7,019	$6,986	$6,953	$6,920	$6,888	$84,813
	b. Debt Component Grossed Up For Taxes (C)		2,043	2,034	2,025	2,015	2,006	1,997	1,988	1,979	1,969	1,960	1,951	1,942	23,909
8.	Investment Expenses														
	a. Depreciation (D)		6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	6,397	76,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		15,688	15,646	15,604	15,562	15,520	15,478	15,436	15,395	15,352	15,310	15,268	15,227	185,486
	a. Recoverable Costs Allocated to Energy		15,688	15,646	15,604	15,562	15,520	15,478	15,436	15,395	15,352	15,310	15,268	15,227	185,486
	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)		15,688	15,646	15,604	15,562	15,520	15,478	15,436	15,395	15,352	15,310	15,268	15,227	185,486
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)		$15,688	$15,646	$15,604	$15,562	$15,520	$15,478	$15,436	$15,395	$15,352	$15,310	$15,268	$15,227	$185,486

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(863,521)	(869,018)	(874,515)	(880,012)	(885,509)	(891,006)	(896,503)	(902,000)	(907,497)	(912,994)	(918,491)	(923,988)	(929,485)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$785,600	780,103	774,606	769,109	763,612	758,115	752,618	747,121	741,624	736,127	730,630	725,133	719,636	
6.	Average Net Investment		782,852	777,355	771,858	766,361	760,864	755,367	749,870	744,373	738,876	733,379	727,882	722,385	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,008	$3,979	$3,951	$3,923	$3,895	$3,867	$3,839	$3,811	$3,782	$3,754	$3,726	$3,698	$46,233
	b. Debt Component Grossed Up For Taxes (C)		1,130	1,122	1,114	1,106	1,098	1,090	1,082	1,074	1,066	1,058	1,050	1,042	13,032
8.	Investment Expenses														
	a. Depreciation (D)		5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	5,497	65,964
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,635	10,598	10,562	10,526	10,490	10,454	10,418	10,382	10,345	10,309	10,273	10,237	125,229
	a. Recoverable Costs Allocated to Energy		10,635	10,598	10,562	10,526	10,490	10,454	10,418	10,382	10,345	10,309	10,273	10,237	125,229
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,635	10,598	10,562	10,526	10,490	10,454	10,418	10,382	10,345	10,309	10,273	10,237	125,229
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,635	$10,598	$10,562	$10,526	$10,490	$10,454	$10,418	$10,382	$10,345	$10,309	$10,273	$10,237	$125,229

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(769,892)	(774,769)	(779,646)	(784,523)	(789,400)	(794,277)	(799,154)	(804,031)	(808,908)	(813,785)	(818,662)	(823,539)	(828,416)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$811,995	807,118	802,241	797,364	792,487	787,610	782,733	777,856	772,979	768,102	763,225	758,348	753,471	
6.	Average Net Investment		809,557	804,680	799,803	794,926	790,049	785,172	780,295	775,418	770,541	765,664	760,787	755,910	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,144	$4,119	$4,094	$4,069	$4,044	$4,019	$3,995	$3,970	$3,945	$3,920	$3,895	$3,870	$48,084
	b. Debt Component Grossed Up For Taxes (C)		1,168	1,161	1,154	1,147	1,140	1,133	1,126	1,119	1,112	1,105	1,098	1,091	13,554
8.	Investment Expenses														
	a. Depreciation (D)		4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	4,877	58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,189	10,157	10,125	10,093	10,061	10,029	9,998	9,966	9,934	9,902	9,870	9,838	120,162
	a. Recoverable Costs Allocated to Energy		10,189	10,157	10,125	10,093	10,061	10,029	9,998	9,966	9,934	9,902	9,870	9,838	120,162
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,189	10,157	10,125	10,093	10,061	10,029	9,998	9,966	9,934	9,902	9,870	9,838	120,162
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,189	$10,157	$10,125	$10,093	$10,061	$10,029	$9,998	$9,966	$9,934	$9,902	$9,870	$9,838	$120,162

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(1,118,510)	(1,126,463)	(1,134,416)	(1,142,369)	(1,150,322)	(1,158,275)	(1,166,228)	(1,174,181)	(1,182,134)	(1,190,087)	(1,198,040)	(1,205,993)	(1,213,946)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,587,997	1,580,044	1,572,091	1,564,138	1,556,185	1,548,232	1,540,279	1,532,326	1,524,373	1,516,420	1,508,467	1,500,514	1,492,561	
6.	Average Net Investment		1,584,021	1,576,068	1,568,115	1,560,162	1,552,209	1,544,256	1,536,303	1,528,350	1,520,397	1,512,444	1,504,491	1,496,538	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$8,109	$8,068	$8,028	$7,987	$7,946	$7,905	$7,865	$7,824	$7,783	$7,743	$7,702	$7,661	$94,621
	b. Debt Component Grossed Up For Taxes (C)		2,286	2,274	2,263	2,251	2,240	2,228	2,217	2,206	2,194	2,183	2,171	2,160	26,673
8.	Investment Expenses														
	a. Depreciation (D)		7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	7,953	95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,348	18,295	18,244	18,191	18,139	18,086	18,035	17,983	17,930	17,879	17,826	17,774	216,730
	a. Recoverable Costs Allocated to Energy		18,348	18,295	18,244	18,191	18,139	18,086	18,035	17,983	17,930	17,879	17,826	17,774	216,730
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		18,348	18,295	18,244	18,191	18,139	18,086	18,035	17,983	17,930	17,879	17,826	17,774	216,730
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,348	$18,295	$18,244	$18,191	$18,139	$18,086	$18,035	$17,983	$17,930	$17,879	$17,826	$17,774	$216,730

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(39,979,614)	(40,288,780)	(40,597,946)	(40,907,112)	(41,216,278)	(41,525,444)	(41,834,610)	(42,143,776)	(42,452,942)	(42,762,108)	(43,071,274)	(43,380,440)	(43,689,606)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$45,739,488	45,430,322	45,121,156	44,811,990	44,502,824	44,193,658	43,884,492	43,575,326	43,266,160	42,956,994	42,647,828	42,338,662	42,029,496	
6.	Average Net Investment		45,584,905	45,275,739	44,966,573	44,657,407	44,348,241	44,039,075	43,729,909	43,420,743	43,111,577	42,802,411	42,493,245	42,184,079	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$233,361	$231,778	$230,195	$228,612	$227,030	$225,447	$223,864	$222,282	$220,699	$219,116	$217,534	$215,951	$2,695,869
	b. Debt Component Grossed Up For Taxes (C)		65,783	65,337	64,891	64,444	63,998	63,552	63,106	62,660	62,214	61,767	61,321	60,875	759,948
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)		608,310	606,281	604,252	602,222	600,194	598,165	596,136	594,108	592,079	590,049	588,021	585,992	7,165,809
	a. Recoverable Costs Allocated to Energy		608,310	606,281	604,252	602,222	600,194	598,165	596,136	594,108	592,079	590,049	588,021	585,992	7,165,809
	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)		608,310	606,281	604,252	602,222	600,194	598,165	596,136	594,108	592,079	590,049	588,021	585,992	7,165,809
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)		$608,310	$606,281	$604,252	$602,222	$600,194	$598,165	$596,136	$594,108	$592,079	$590,049	$588,021	$585,992	$7,165,809

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 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8% and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2021 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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)	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	$96,538,133	
3.	Less: Accumulated Depreciation	(42,023,760)	(42,336,137)	(42,648,514)	(42,960,891)	(43,273,268)	(43,585,645)	(43,898,022)	(44,210,399)	(44,522,776)	(44,835,153)	(45,147,530)	(45,459,907)	(45,772,284)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$54,514,373	54,201,996	53,889,619	53,577,242	53,264,865	52,952,488	52,640,111	52,327,734	52,015,357	51,702,980	51,390,603	51,078,226	50,765,849	
6.	Average Net Investment		54,358,184	54,045,807	53,733,430	53,421,053	53,108,676	52,796,299	52,483,922	52,171,545	51,859,168	51,546,791	51,234,414	50,922,037	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$278,273	$276,674	$275,075	$273,476	$271,877	$270,277	$268,678	$267,079	$265,480	$263,881	$262,282	$260,683	$3,233,735
	b. Debt Component Grossed Up For Taxes (C)		78,443	77,993	77,542	77,091	76,640	76,189	75,739	75,288	74,837	74,386	73,936	73,485	911,569
8.	Investment Expenses														
	a. Depreciation (D)		312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	312,377	3,748,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		669,093	667,044	664,994	662,944	660,894	658,843	656,794	654,744	652,694	650,644	648,595	646,545	7,893,828
	a. Recoverable Costs Allocated to Energy		669,093	667,044	664,994	662,944	660,894	658,843	656,794	654,744	652,694	650,644	648,595	646,545	7,893,828
	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)		669,093	667,044	664,994	662,944	660,894	658,843	656,794	654,744	652,694	650,644	648,595	646,545	7,893,828
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)		$669,093	$667,044	$664,994	$662,944	$660,894	$658,843	$656,794	$654,744	$652,694	$650,644	$648,595	$646,545	$7,893,828

Notes:

(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($54,456,221), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(37,013,361)	(37,265,435)	(37,517,509)	(37,769,583)	(38,021,657)	(38,273,731)	(38,525,805)	(38,777,879)	(39,029,953)	(39,282,027)	(39,534,101)	(39,786,175)	(40,038,249)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$44,751,241	44,499,167	44,247,093	43,995,019	43,742,945	43,490,871	43,238,797	42,986,723	42,734,649	42,482,575	42,230,501	41,978,427	41,726,353	
6.	Average Net Investment		44,625,204	44,373,130	44,121,056	43,868,982	43,616,908	43,364,834	43,112,760	42,860,686	42,608,612	42,356,538	42,104,464	41,852,390	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$228,448	$227,157	$225,867	$224,576	$223,286	$221,995	$220,705	$219,415	$218,124	$216,834	$215,543	$214,253	$2,656,203
	b. Debt Component Grossed Up For Taxes (C)		64,398	64,034	63,670	63,307	62,943	62,579	62,215	61,852	61,488	61,124	60,760	60,396	748,766
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)		544,920	543,265	541,611	539,957	538,303	536,648	534,994	533,341	531,686	530,032	528,377	526,723	6,429,857
	a. Recoverable Costs Allocated to Energy		544,920	543,265	541,611	539,957	538,303	536,648	534,994	533,341	531,686	530,032	528,377	526,723	6,429,857
	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)		544,920	543,265	541,611	539,957	538,303	536,648	534,994	533,341	531,686	530,032	528,377	526,723	6,429,857
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)		$544,920	$543,265	$541,611	$539,957	$538,303	$536,648	$534,994	$533,341	$531,686	$530,032	$528,377	$526,723	$6,429,857

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 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$50,000	$125,000	$75,000	$50,000	$250,000	$200,000	$45,000	$0	$0	$795,000
	b. Clearings to Plant		0	0	0	0	0	0	0	550,000	200,000	45,000	0	0	795,000
	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)	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$66,814,861	$67,364,861	$67,564,861	$67,609,861	$67,609,861	$67,609,861	
3.	Less: Accumulated Depreciation	(29,385,303)	(29,577,771)	(29,770,239)	(29,962,707)	(30,155,175)	(30,347,643)	(30,540,111)	(30,732,579)	(30,925,047)	(31,118,890)	(31,313,233)	(31,507,689)	(31,702,145)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	50,000	175,000	250,000	300,000	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$37,429,558	37,237,090	37,044,622	36,852,154	36,709,686	36,642,218	36,524,750	36,382,282	36,439,814	36,445,971	36,296,628	36,102,172	35,907,716	
6.	Average Net Investment		37,333,324	37,140,856	36,948,388	36,780,920	36,675,952	36,583,484	36,453,516	36,411,048	36,442,892	36,371,299	36,199,400	36,004,944	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$191,119	$190,133	$189,148	$188,291	$187,753	$187,280	$186,615	$186,397	$186,560	$186,194	$185,314	$184,318	$2,249,122
	b. Debt Component Grossed Up For Taxes (C)		53,875	53,597	53,320	53,078	52,926	52,793	52,605	52,544	52,590	52,487	52,239	51,958	634,012
8.	Investment Expenses														
	a. Depreciation (D)		192,468	192,468	192,468	192,468	192,468	192,468	192,468	192,468	193,843	194,343	194,456	194,456	2,316,842
	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)		437,462	436,198	434,936	433,837	433,147	432,541	431,688	431,409	432,993	433,024	432,009	430,732	5,199,976
	a. Recoverable Costs Allocated to Energy		437,462	436,198	434,936	433,837	433,147	432,541	431,688	431,409	432,993	433,024	432,009	430,732	5,199,976
	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)		437,462	436,198	434,936	433,837	433,147	432,541	431,688	431,409	432,993	433,024	432,009	430,732	5,199,976
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)		$437,462	$436,198	$434,936	$433,837	$433,147	$432,541	$431,688	$431,409	$432,993	$433,024	$432,009	$430,732	$5,199,976

Notes:
(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($38,069,546), 315.54 ($10,642,027), 316.54 ($687,934), 315.40 ($558,103), and 312.44 ($795,000)
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rates are 2.4%, 3.8%, 3.9%, 3.3%, 3.7%, and 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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)	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	$24,467,806	
3.	Less: Accumulated Depreciation	(6,453,865)	(6,505,447)	(6,557,029)	(6,608,611)	(6,660,193)	(6,711,775)	(6,763,357)	(6,814,939)	(6,866,521)	(6,918,103)	(6,969,685)	(7,021,267)	(7,072,849)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$18,013,941	17,962,359	17,910,777	17,859,195	17,807,613	17,756,031	17,704,449	17,652,867	17,601,285	17,549,703	17,498,121	17,446,539	17,394,957	
6.	Average Net Investment		17,988,150	17,936,568	17,884,986	17,833,404	17,781,822	17,730,240	17,678,658	17,627,076	17,575,494	17,523,912	17,472,330	17,420,748	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$92,086	$91,822	$91,558	$91,294	$91,030	$90,766	$90,501	$90,237	$89,973	$89,709	$89,445	$89,181	$1,087,602
	b. Debt Component Grossed Up For Taxes (C)		25,958	25,884	25,810	25,735	25,661	25,586	25,512	25,437	25,363	25,288	25,214	25,140	306,588
8.	Investment Expenses														
	a. Depreciation (D)		51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	51,582	618,984
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		169,626	169,288	168,950	168,611	168,273	167,934	167,595	167,256	166,918	166,579	166,241	165,903	2,013,174
	a. Recoverable Costs Allocated to Energy		169,626	169,288	168,950	168,611	168,273	167,934	167,595	167,256	166,918	166,579	166,241	165,903	2,013,174
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		169,626	169,288	168,950	168,611	168,273	167,934	167,595	167,256	166,918	166,579	166,241	165,903	2,013,174
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$169,626	$169,288	$168,950	$168,611	$168,273	$167,934	$167,595	$167,256	$166,918	$166,579	$166,241	$165,903	$2,013,174

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45 ($23,011,597) and 312.44 ($1,456,209).
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 2.5% and 3.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20200007-EI
ECRC 2021 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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)	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	$8,621,413	
3.	Less: Accumulated Depreciation	(1,955,259)	(1,977,555)	(1,999,851)	(2,022,147)	(2,044,443)	(2,066,739)	(2,089,035)	(2,111,331)	(2,133,627)	(2,155,923)	(2,178,219)	(2,200,515)	(2,222,811)	
4.	CWIP - Non-Interest Bearing	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	13,614	
5.	Net Investment (Lines 2 + 3 + 4)	$6,679,769	6,657,473	6,635,177	6,612,881	6,590,585	6,568,289	6,545,993	6,523,697	6,501,401	6,479,105	6,456,809	6,434,513	6,412,217	
6.	Average Net Investment		6,668,621	6,646,325	6,624,029	6,601,733	6,579,437	6,557,141	6,534,845	6,512,549	6,490,253	6,467,957	6,445,661	6,423,365	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$34,138	$34,024	$33,910	$33,796	$33,682	$33,568	$33,454	$33,339	$33,225	$33,111	$32,997	$32,883	$402,127
	b. Debt Component Grossed Up For Taxes (C)		9,623	9,591	9,559	9,527	9,495	9,463	9,430	9,398	9,366	9,334	9,302	9,269	113,357
8.	Investment Expenses														
	a. Depreciation (D)		22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	22,296	267,552
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,057	65,911	65,765	65,619	65,473	65,327	65,180	65,033	64,887	64,741	64,595	64,448	783,036
	a. Recoverable Costs Allocated to Energy		66,057	65,911	65,765	65,619	65,473	65,327	65,180	65,033	64,887	64,741	64,595	64,448	783,036
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		66,057	65,911	65,765	65,619	65,473	65,327	65,180	65,033	64,887	64,741	64,595	64,448	783,036
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$66,057	$65,911	$65,765	$65,619	$65,473	$65,327	$65,180	$65,033	$64,887	$64,741	$64,595	$64,448	$783,036

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 ($2,232), 312.54 ($210,295) and 395.00 ($35,018)
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.2%, 3.1%, 3.5%, 2.9%, 3.3%, 3.8%, and 14.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2021 PROJECTION, FORM 42-4P
EXHIBIT NO. MAS-3, DOCUMENT NO. 4, PAGE 23 OF 29

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(34,246)	(34,238)	(34,238)	(34,238)	(34,229)	(34,229)	(34,229)	(34,221)	(34,221)	(34,221)	(34,212)	(34,212)	(34,212)	
3.	Total Working Capital Balance	($34,246)	(34,238)	(34,238)	(34,238)	(34,229)	(34,229)	(34,229)	(34,221)	(34,221)	(34,221)	(34,212)	(34,212)	(34,212)	
4.	Average Net Working Capital Balance		($34,242)	($34,238)	($34,238)	($34,233)	($34,229)	($34,229)	($34,225)	($34,221)	($34,221)	($34,217)	($34,212)	($34,212)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($175)	($175)	($175)	($175)	($175)	($175)	($175)	($175)	($175)	($175)	($175)	($175)	(2,100)
	b. Debt Component Grossed Up For Taxes (B)		(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(588)
6.	Total Return Component		(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(224)	(2,688)
7.	Expenses:		1	2	3	4	5	6	7	8	9	10	11	12	
	a. Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(4)	4	4	(4)	4	4	(4)	4	4	(4)	4	4	15
8.	Net Expenses (D)		(4)	4	4	(4)	4	4	(4)	4	4	(4)	4	4	15
9.	Total System Recoverable Expenses (Lines 6 + 8)		(228)	(220)	(220)	(228)	(220)	(220)	(228)	(220)	(220)	(228)	(220)	(220)	(2,673)
	a. Recoverable Costs Allocated to Energy		(228)	(220)	(220)	(228)	(220)	(220)	(228)	(220)	(220)	(228)	(220)	(220)	(2,673)
	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)		(228)	(220)	(220)	(228)	(220)	(220)	(228)	(220)	(220)	(228)	(220)	(220)	(2,672)
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)		($228)	($220)	($220)	($228)	($220)	($220)	($228)	($220)	($220)	($228)	($220)	($220)	($2,672)

Notes:
(A) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12.
(C) Line 6 is reported on Schedule 3P.
(D) Line 8 is reported on Schedule 2P.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(3,777,423)	(3,829,302)	(3,881,181)	(3,933,060)	(3,984,939)	(4,036,818)	(4,088,697)	(4,140,576)	(4,192,455)	(4,244,334)	(4,296,213)	(4,348,092)	(4,399,971)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,689,936	17,638,057	17,586,178	17,534,299	17,482,420	17,430,541	17,378,662	17,326,783	17,274,904	17,223,025	17,171,146	17,119,267	17,067,388	
6.	Average Net Investment		17,663,997	17,612,118	17,560,239	17,508,360	17,456,481	17,404,602	17,352,723	17,300,844	17,248,965	17,197,086	17,145,207	17,093,328	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$90,426	$90,161	$89,895	$89,630	$89,364	$89,099	$88,833	$88,567	$88,302	$88,036	$87,771	$87,505	$1,067,589
	b. Debt Component Grossed Up For Taxes (C)		25,491	25,416	25,341	25,266	25,191	25,116	25,041	24,967	24,892	24,817	24,742	24,667	300,947
8.	Investment Expenses														
	a. Depreciation (D)		51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	622,548
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		167,796	167,456	167,115	166,775	166,434	166,094	165,753	165,413	165,073	164,732	164,392	164,051	1,991,084
	a. Recoverable Costs Allocated to Energy		167,796	167,456	167,115	166,775	166,434	166,094	165,753	165,413	165,073	164,732	164,392	164,051	1,991,084
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		167,796	167,456	167,115	166,775	166,434	166,094	165,753	165,413	165,073	164,732	164,392	164,051	1,991,084
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$167,796	$167,456	$167,115	$166,775	$166,434	$166,094	$165,753	$165,413	$165,073	$164,732	$164,392	$164,051	$1,991,084

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend CCR Rule - Phase I
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$421,000	$389,000	$165,000	$45,000	$2,500	$2,500	$0	$0	$0	$0	$0	$0	$1,025,000
	b. Clearings to Plant		0	600,000	115,000	35,000	0	0	0	0	0	2,361,187	0	0	3,111,187
	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)	$930,303	$930,303	$1,530,303	$1,645,303	$1,680,303	$1,680,303	$1,680,303	$1,680,303	$1,680,303	$1,680,303	$4,041,490	$4,041,490	$4,041,490	
3.	Less: Accumulated Depreciation	(77,769)	(80,073)	(82,377)	(86,381)	(90,711)	(95,140)	(99,569)	(103,998)	(108,427)	(112,856)	(117,285)	(128,404)	(139,523)	
4.	CWIP - Non-Interest Bearing	2,086,187	2,507,187	2,296,187	2,346,187	2,356,187	2,358,687	2,361,187	2,361,187	2,361,187	2,361,187	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,938,721	3,357,417	3,744,113	3,905,109	3,945,779	3,943,850	3,941,921	3,937,492	3,933,063	3,928,634	3,924,205	3,913,086	3,901,967	
6.	Average Net Investment		3,148,069	3,550,765	3,824,611	3,925,444	3,944,814	3,942,885	3,939,706	3,935,277	3,930,848	3,926,419	3,918,645	3,907,526	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$16,116	$18,177	$19,579	$20,095	$20,194	$20,185	$20,168	$20,146	$20,123	$20,100	$20,061	$20,004	$234,948
	b. Debt Component Grossed Up For Taxes (C)		4,543	5,124	5,519	5,665	5,693	5,690	5,685	5,679	5,673	5,666	5,655	5,639	66,231
8.	Investment Expenses														
	a. Depreciation (D)		2,304	2,304	4,004	4,330	4,429	4,429	4,429	4,429	4,429	4,429	11,119	11,119	61,754
	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)		22,963	25,605	29,102	30,090	30,316	30,304	30,282	30,254	30,225	30,195	36,835	36,762	362,933
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		22,963	25,605	29,102	30,090	30,316	30,304	30,282	30,254	30,225	30,195	36,835	36,762	362,933
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)		22,963	25,605	29,102	30,090	30,316	30,304	30,282	30,254	30,225	30,195	36,835	36,762	362,933
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$22,963	$25,605	$29,102	$30,090	$30,316	$30,304	$30,282	$30,254	$30,225	$30,195	$36,835	$36,762	$362,933

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40 ($261,568), 312.44 ($668,735), and 312.40 ($3,111,187)
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 2.9%, 3.0%, and 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend CCR Rule - Phase II
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$130,000	$85,000	$160,000	$41,368	$37,000	$8,000	$5,000	$5,000	$0	$0	$0	$0	$471,368
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	3,999,853	0	0	3,999,853
	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	$3,999,853	$3,999,853	$3,999,853	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(10,000)	(20,000)	
4.	CWIP - Non-Interest Bearing	3,528,485	3,658,485	3,743,485	3,903,485	3,944,853	3,981,853	3,989,853	3,994,853	3,999,853	3,999,853	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$3,528,485	3,658,485	3,743,485	3,903,485	3,944,853	3,981,853	3,989,853	3,994,853	3,999,853	3,999,853	3,999,853	3,989,853	3,979,853	
6.	Average Net Investment		3,593,485	3,700,985	3,823,485	3,924,169	3,963,353	3,985,853	3,992,353	3,997,353	3,999,853	3,999,853	3,994,853	3,984,853	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$18,396	$18,946	$19,573	$20,089	$20,289	$20,405	$20,438	$20,463	$20,476	$20,476	$20,451	$20,399	$240,401
	b. Debt Component Grossed Up For Taxes (C)		5,186	5,341	5,518	5,663	5,719	5,752	5,761	5,769	5,772	5,772	5,765	5,750	67,768
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	10,000	10,000	20,000
	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)		23,582	24,287	25,091	25,752	26,008	26,157	26,199	26,232	26,248	26,248	36,216	36,149	328,169
	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		23,582	24,287	25,091	25,752	26,008	26,157	26,199	26,232	26,248	26,248	36,216	36,149	328,169
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)		23,582	24,287	25,091	25,752	26,008	26,157	26,199	26,232	26,248	26,248	36,216	36,149	328,169
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$23,582	$24,287	$25,091	$25,752	$26,008	$26,157	$26,199	$26,232	$26,248	$26,248	$36,216	$36,149	$328,169

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

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

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$890,366	$512,033	$885,870	$890,299	$885,870	$1,063,044	$1,266,794	$1,314,333	$1,240,218	$1,281,475	$1,257,935	$1,328,804	$12,817,041
	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	4,261,136	5,151,502	5,663,535	6,549,405	7,439,704	8,325,574	9,388,618	10,655,412	11,969,745	13,209,963	14,491,438	15,749,373	17,078,177	
5.	Net Investment (Lines 2 + 3 + 4)	$4,261,136	5,151,502	5,663,535	6,549,405	7,439,704	8,325,574	9,388,618	10,655,412	11,969,745	13,209,963	14,491,438	15,749,373	17,078,177	
6.	Average Net Investment		4,706,319	5,407,518	6,106,470	6,994,554	7,882,639	8,857,096	10,022,015	11,312,578	12,589,854	13,850,700	15,120,405	16,413,775	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$24,093	$27,682	$31,261	$35,807	$40,353	$45,342	$51,305	$57,912	$64,451	$70,905	$77,405	$84,026	$610,542
	b. Debt Component Grossed Up For Taxes (C)		6,792	7,803	8,812	10,094	11,375	12,782	14,463	16,325	18,168	19,988	21,820	23,686	172,108
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)		30,885	35,485	40,073	45,901	51,728	58,124	65,768	74,237	82,619	90,893	99,225	107,712	782,650
	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		30,885	35,485	40,073	45,901	51,728	58,124	65,768	74,237	82,619	90,893	99,225	107,712	782,650
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)		30,885	35,485	40,073	45,901	51,728	58,124	65,768	74,237	82,619	90,893	99,225	107,712	782,650
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$30,885	$35,485	$40,073	$45,901	$51,728	$58,124	$65,768	$74,237	$82,619	$90,893	$99,225	$107,712	$782,650

Notes:

(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Sec. 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$470,042	$452,000	$772,000	$651,000	$719,000	$865,000	$960,000	$1,100,000	$2,508,912	$821,239	$670,000	$467,807	$10,457,000
	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	1,051,430	1,521,472	1,973,472	2,745,472	3,396,472	4,115,472	4,980,472	5,940,472	7,040,472	9,549,384	10,370,623	11,040,623	11,508,430	
5.	Net Investment (Lines 2 + 3 + 4)	$1,051,430	1,521,472	1,973,472	2,745,472	3,396,472	4,115,472	4,980,472	5,940,472	7,040,472	9,549,384	10,370,623	11,040,623	11,508,430	
6.	Average Net Investment		1,286,451	1,747,472	2,359,472	3,070,972	3,755,972	4,547,972	5,460,472	6,490,472	8,294,928	9,960,004	10,705,623	11,274,527	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$6,586	$8,946	$12,079	$15,721	$19,228	$23,282	$27,954	$33,226	$42,464	$50,988	$54,805	$57,717	$352,996
	b. Debt Component Grossed Up For Taxes (C)		1,856	2,522	3,405	4,432	5,420	6,563	7,880	9,366	11,970	14,373	15,449	16,270	99,506
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,442	11,468	15,484	20,153	24,648	29,845	35,834	42,592	54,434	65,361	70,254	73,987	452,502
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		8,442	11,468	15,484	20,153	24,648	29,845	35,834	42,592	54,434	65,361	70,254	73,987	452,502
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		8,442	11,468	15,484	20,153	24,648	29,845	35,834	42,592	54,434	65,361	70,254	73,987	452,502
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,442	$11,468	$15,484	$20,153	$24,648	$29,845	$35,834	$42,592	$54,434	$65,361	$70,254	$73,987	$452,502

Notes:

(A) Applicable depreciable base for Big Bend; accounts TBD depending on type of plant added
(B) Line 6 x 6.1431% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(C) Line 6 x 1.7317% x 1/12.
(D) Applicable depreciation rate is TBD depending on type of plant added
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 Flue Gas Desulfurization Integration

Project Description:

This project involved the integration of Big Bend Unit 3 flue gases into the Big Bend Unit 4 Flue Gas Desulfurization ("FGD") system. The integration was accomplished by installing interconnecting ductwork between Unit 3 precipitator outlet ducts and the Unit 4 FGD inlet duct. The Unit 4 FGD outlet duct was interconnected with the Unit 3 chimney via new ductwork and a new stack breaching. New ductwork, linings, isolation dampers, support steel, and stack annulus pressurization fans were procured and installed. Modifications to the materials handling systems and controls were also necessary.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020, is $924,091 compared to the original projection of $925,246.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $280,339 compared to the original projection of $390,754. The variance is -28.3 percent and is due to Big Bend Unit 3 operating less than originally projected. As a result, less maintenance is required.

Progress Summary: This project was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $906,095.

There are not any projected O&M costs for the period January 2021 through December 2021.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Units 1 & 2 Flue Gas Conditioning

Project Description:

The existing electrostatic precipitators were not designed for the range of fuels needed for compliance with the Clean Air Act Amendments ("CAAA"). Flue gas conditioning was required to assure operation of the generating units in accordance with applicable permits and regulations. This equipment is still required to ensure compliance with the CAAA in the event the FGD system on Units 1 & 2 is not operating.

The project involved the addition of molten sulfur unloading, storage and conveying to sulfur burners and catalytic converters where SO_2 is converted to SO_3. The control and injection system then injects this into the ductwork ahead of the electrostatic precipitators.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $221,125 compared to the original projection of $221,202.

There are not any actual/estimated O&M costs projected, nor are there any projected O&M costs in the original projection for the period January 2020 through December 2020.

Progress Summary: This project was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $193,042.

There are not any O&M costs projected for the period of January 2021 through December 2021.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 4 Continuous Emissions Monitors

Project Description:

Continuous emissions monitors ("CEMs") were installed on the flue gas inlet and outlet of Big Bend Unit 4 to monitor compliance with the CAAA requirements. The monitors are capable of measuring, recording and electronically reporting SO_2, NO_x and volumetric gas flow out of the stack. The project consisted of monitors, a CEM building, the CEMs control and power cables to supply a complete system.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMs and specific requirements for the monitoring of pollutants, opacity and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMs, and in essence, they define the components needed and their configuration.

Project Accomplishment:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $47,462 compared to the original projection of $47,504.

Progress Summary: This project was approved by the Commission in Docket No. 19960688-EI, Order No. PSC-1996-1048-FOF-EI, issued August 14, 1996. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $45,598.

Tampa Electric Company
Environmental Cost Recovery Clause
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Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 1 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements optimize coal fineness by providing a uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, enables a uniform, staged combustion. As a result, firing systems operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $73,018 compared to the original projection of $73,061.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-1764-FOF-EI, issued December 31, 1998. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $69,201.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 2 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 2 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, enables a uniform, staged combustion. As a result, firing systems operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $53,081 compared to the original projection of $53,118.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-1764-FOF-EI, issued December 31, 1998. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $50,482.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Units 1 & 2 FGD

Project Description:

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing SO_2 from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II was required by January 1, 2000. The CAAA impose SO_2 emission limits on existing steam electric units with an output capacity of greater than 25 megawatts and all new utility units. Tampa Electric conducted an exhaustive analysis of options to comply with Phase II of the CAAA that culminated in the selection of the FGD project to serve Big Bend Units 1 & 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $5,648,115 compared to the original projection of $5,653,336.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $138,950 compared to the original estimate of $250,146, resulting in a variance of -44.5 percent. This variance is due to Big Bend Units 1 and 2 operating less than projected. As a result, less maintenance is required.

Progress Summary: This project was approved by the Commission in Docket No. 19980693-EI, Order No. PSC-1999-0075-FOF-EI, issued January 11, 1999. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $5,440,931.

There are not any O&M costs projected for the period January 2021 through December 2021.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Section 114 Mercury Testing Platform

Project Description:

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance of emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform specialized mercury testing of the inlet and outlet of the last emission control device installed for Big Bend Units 1, 2 or 3, and Polk Unit 1 as part of the mercury data collection. Part of the cost incurred to perform the stack testing is due to the need to construct special test facilities at the Big Bend stack testing location to meet EPA's testing requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020, is $8,161 compared to the original projection of $8,169.

Progress Summary: This project was approved by the Commission in Docket No. 19990976-EI, Order No. PSC-1999-2103-PAA-EI, issued October 25, 1999. The project was placed in service in December 1999 and completed in May 2000.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $7,958.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend FGD Optimization and Utilization

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to optimize the SO_2 removal efficiency and operations of the Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric performed activities in three key areas to improve the performance and reliability of the Big Bend Units 1, 2 and 3 FGD systems. The majority of the improvements required on the Unit 3 tower module included the tower piping, nozzle and internal improvements, ductwork improvements, electrical system reliability improvements, tower control improvements, dibasic acid system improvements, booster fan reliability, absorber system improvements, quencher system improvements, and tower demister improvements. Big Bend Units 1 and 2 FGD system improvements included additional preventative maintenance, oxidation air control improvements, and tower water, air reagent and start-up piping upgrades. In order to ensure reliability of the FGD systems, improvements to the common limestone supply, gypsum de-watering stack reliability and wastewater treatment plant were also performed.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $1,536,807 compared to the original projection of $1,538,736.

Progress Summary: This project was approved by the Commission in Docket No. 20000685-EI, Order No. PSC-2000-1906-PAA-EI, issued October 18, 2000. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $1,507,233.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend PM Minimization and Monitoring

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to develop a Best Operational Practices ("BOP") study to minimize emissions from each electrostatic precipitator ("ESP") at Big Bend, as well as perform a best available control technology ("BACT") analysis for the upgrade of each existing ESP. The company is also required to install and operate particulate matter continuous emission monitors on Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric identified improvements that were necessary to optimize ESP performance such as modifications to the turning vanes and precipitator distribution plates, and upgrades to the controls and software system of the precipitators. Tampa Electric incurred costs associated with the recommendations of the BOP study and the BACT analysis in 2001 and continues to make O&M and capital expenditures.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $1,726,237 compared to the original projection of $1,728,246.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $301,141 compared to the original projection of $398,500, resulting in a variance of -24.4 percent. This variance is due to Big Bend Units operating less than projected. As a result, less maintenance is required.

Progress Summary: This project was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-PAA-EI, issued November 6, 2000. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $1,684,675.

The estimated O&M costs for the period January 2021 through December 2021 are $252,000.

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Project Title: Big Bend NO_x Emissions Reduction

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to spend up to $3 million with the goal to reduce NO_x emissions at Big Bend Station. By 2002, the Consent Decree required the company to achieve at least a 30 percent reduction beyond 1998 NO_x emission levels for Big Bend Units 1 and 2 and at least a 15 percent reduction in NO_x emissions from Big Bend Unit 3. Tampa Electric identified and completed projects that were the first steps to decrease NO_x emissions in these units such as burner and windbox modifications and the installation of a neural network system on each of the Big Bend units.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $490,945 compared to the original projection of $491,669.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $6,006 compared to the original projection of $12,000, resulting in a variance of -50.0 percent. The variance in expenditures associated with the Big Bend NO_x Emissions Reduction project is due to planned outages for Units 3 and 4 that were not included in the estimate. This resulted in fewer hours of unit operation than originally estimated. Due to the reduced operation, less maintenance is needed.

Progress Summary: This project was approved by the Commission in Docket No. 20001186-EI, Order No. PSC-2000-2104-PAA-EI, issued November 6, 2000. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $487,214.

The estimated O&M costs projected for the period January 2021 through December 2021 are $2,028.

Tampa Electric Company
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Project Title: Big Bend Fuel Oil Tank No. 1 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 1 Upgrade is a 500,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEl Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $68,615 compared to the original projection of $68,637.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-0408-FOF-EI, issued March 18, 1998. The project has been retired.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is projected to be $63,896.

Tampa Electric Company
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Project Title: Big Bend Fuel Oil Tank No. 2 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 2 is a 4,200,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEl Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $112,855 compared to the original projection of $112,892.

Progress Summary: This project was approved by the Commission in Docket No. 19980007-EI, Order No. PSC-1998-0408-FOF-EI, issued March 18, 1998. The project has been retired.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $105,098.

Tampa Electric Company
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Project Title: SO_2 Emission Allowances

Project Description:

The acid rain control title of the CAAA sets forth a comprehensive regulatory mechanism designed to control acid rain by limiting sulfur dioxide emissions by electric utilities. The CAAA requires reductions in SO_2 emissions in two phases. Phase I began on January 1, 1995 and applies to 110 mostly coal-fired utility plants containing about 260 generating units. These plants are owned by some 40 jurisdictional utility systems that are expected to reduce annual SO_2 emissions by as much as 4.5 million tons. Phase II began on January 1, 2000, and applies to virtually all existing steam-electric generating utility units with capacity exceeding 25 megawatts and to new generating utility units of any size. The EPA issues to the owners of generating units allowances (defined as an authorization to emit, during or after a specified calendar year, one ton of SO_2) equal to the number of tons of SO_2 emissions authorized by the CAAA. EPA does not assess a charge for the allowances it awards.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated return on average net working capital for the period January 2020 through December 2020 is ($2,658) compared to the original projection of ($2,664).

The actual/estimated O&M costs for the period January 2020 through December 2020 are ($18) compared to the original projection of $71. The variance is not material.

Progress Summary: SO_2 emission allowances are being used by Tampa Electric to meet compliance standards for Phase I of the CAAA.

Project Projections: The estimated return on average net working capital for the period January 2021 through December 2021 is ($2,688).

The estimated O&M costs for the period January 2021 through December 2021 are $15.

Tampa Electric Company
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Project Title: National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees

Project Description:

Chapter 62-4.052, Florida Administrative Code ("F.A.C."), implements the annual regulatory program and surveillance fees for wastewater permits. These fees are in addition to the application fees described in Rule 62-4.050, F.A.C. Tampa Electric's Big Bend, Polk, and Bayside Stations are affected by this rule.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2020 through December 2020 is $34,500 compared to the original projection of $34,500.

Progress Summary: NPDES Surveillance fees are paid annually for the prior year.

Projections: The estimated O&M costs for the period January 2021 through December 2021 are $23,500.

Tampa Electric Company
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Project Title: Gannon Thermal Discharge Study

Project Description:

This project was a direct requirement from the FDEP in conjunction with the renewal of Tampa Electric's Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code, which constitute authorization for the company's Gannon Station facility to discharge to waters of the State under the NPDES. The FDEP permit is Permit No. FL0000809. Specifically, Tampa Electric was required to perform a 316(a) determination for Gannon Station to ensure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife within the primary area of study. The project had two facets: 1) developing a plan of study and identified the thermal plume, and 2) implemented the plan of study through appropriate sampling to make the determination if any adverse impacts are occurring.

Project Accomplishments:

Fiscal Expenditures: There are not any actual/estimated O&M costs projected, nor were there any in the original projection for the period January 2020 through December 2020.

Progress Summary: This project was approved by the Commission in Docket No. 20010593-EI, Order No. PSC-2001-1847-PAA-EI on September 4, 2001. The project is complete and in service.

Projections: There are not any O&M costs projected for the period January 2021 through December 2021.

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Project Title: Polk NO_x Emissions Reduction

Project Description:

This project was designed to meet a lower NO_x emissions limit established by the FDEP for Polk Unit 1 by July 1, 2005. The lower limit of 15 parts per million by volume dry basis at 15 percent O_2 is specified in FDEP Permit No. PSD-FL-194F issued February 5, 2002. The project consisted of two phases: 1) the humidification of syngas through the installation of a syngas saturator; and 2) the modification of controls and the installation of additional guide vanes to the diluent nitrogen compressor.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $106,750 compared to the original projection of $106,858.

There are not any actual/estimated O&M costs projected, nor were there any in the original projection for the period January 2020 through December 2020.

Progress Summary: This project was approved by the Commission in Docket No. 20020726-EI, Order No. PSC-2002-1445-PAA-EI on October 21, 2002. The project is complete and in service.

Project Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $103,428.

There are not any O&M costs projected for the period of January 2021 through December 2021.

Tampa Electric Company
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Project Title: Bayside SCR Consumables

Project Description:

This project is necessary to achieve the NO_x emissions limit of 3.5 parts per million established by the FDEP Consent Final Judgment and the EPA Consent Decree for the natural gas-fired Bayside Power Station. To achieve this NO_x limit, the installation of selective catalytic reduction (SCR) systems is required. An SCR system requires consumable goods – primarily anhydrous ammonia – to be injected into the catalyst bed in order to achieve the required NO_x emissions limit. Principally, the project was designed to capture the cost of consumable goods necessary to operate the SCR systems.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2020 through December 2020 are $93,185 compared to the original projection of $119,000. The variance is -21.7 percent. The variance is due to less consumables required than originally expected.

Progress Summary: This project was approved by the Commission in Docket No. 20021255-EI, Order No. PSC-2003-0469-PAA-EI, issued April 4, 2003. Annual O&M expenses will continue to be incurred.

Projections: The estimated O&M costs for the period January 2021 through December 2021 are projected to be $119,000.

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Project Title: Big Bend Unit 4 Separated Overfire Air ("SOFA")

Project Description:

This project is necessary to assist in achieving the NO_x emissions limit established by the FDEP Consent Final Judgment and the EPA Consent Decree for Big Bend Unit 4. A SOFA system stages secondary combustion air to prevent NO_x formation that would otherwise require removal by post-combustion technology. In-furnace combustion control through a SOFA system is the most cost-effective means to reduce NO_x emissions prior to the application of these technologies. Costs associated with the SOFA system entailed capital expenditures for equipment installation and subsequent annual maintenance.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $189,720 compared to the original projection of $189,948.

There are not any actual/estimated O&M costs projected, nor were there any in the original projection for the period January 2020 through December 2020.

Progress Summary: This project was approved by the Commission in Docket No. 20030226-EI, Order No. PSC-2003-0684-PAA-EI, issued June 6, 2003. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $185,486.

There are not any O&M costs projected for the period of January 2021 through December 2021.

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Project Title: Big Bend Unit 1 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2018 through 2020. Thus, the installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements. This project was a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 1 Pre-SCR technologies included a neural network system, secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $129,410 compared to the original projection of $129,539.

The actual/estimated O&M costs for this project for the period January 2020 through December 2020 are $5,400 compared to the original projection of $10,800. The variance is -50.0 percent and is due to Unit 1 running on natural gas rather than coal.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-CO-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $125,229.

There are not any O&M costs projected for the period of January 2021 through December 2021.

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Project Title: Big Bend Unit 2 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2020 through 2020. Thus, the installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements. This project was a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 2 Pre-SCR technologies included secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $123,724 compared to the original projection of $123,858.

The actual/estimated O&M costs for this project for the period January 2020 through December 2020 are $6,175 compared to the original projection of $10,800. The variance is -42.8 percent and is due to less maintenance being required than previously estimated.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-CO-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $120,162.

There are not any O&M costs projected for the period of January 2021 through December 2021.

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Project Title: Big Bend Unit 3 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2020 through 2020. Thus, the installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements. This project was a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 3 Pre-SCR technologies included a neutral network system, secondary air controls, windbox modifications and primary coal/air flow controls.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $222,214 compared to the original projection of $222,468.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $6,815 compared to the original projection of $12,000. The variance is -43.2 percent and is due to Big Bend Unit 3 burning natural gas rather than coal. As a result, less maintenance was required that originally estimated.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-CO-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $216,730.

There are not any O&M costs projected for the period of January 2021 through December 2021.

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Project Title: Clean Water Act Section 316(b) Phase II Study

Project Description:

This project was a direct requirement from the EPA to reduce impingement and entrainment of aquatic organisms related to the withdrawal of waters for cooling purposes through cooling water intake structures. The Phase II Rule requires that power plants meet certain criteria to comply with national performance standards for impingement and entrainment. Accordingly, Tampa Electric must develop its compliance strategies for its Bayside and Big Bend Stations and then submit these strategies for approval through a Comprehensive Demonstration Study to the FDEP.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2020 through December 2020 are $28,110 compared to the original projection of $40,000, resulting in a variance of -29.7 percent. The variance is due to delayed final NPDES Permits for the Big Bend and Bayside Power Stations compared to the estimated timeline. The work will be performed once the permits are received.

Progress Summary: This project was approved by the Commission in Docket No. 20041300-EI, Order No. PSC-2005-0164-PAA-EI, issued February 10, 2005.

Projections: The estimated O&M costs for the period January 2021 through December 2021 are $45,000.

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Project Title: Big Bend Unit 1 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $7,398,711 compared to the original projection of $7,406,274.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $87,529 compared to the original projection of $164,668, resulting in a variance of -46.8 percent. This variance is due to fewer operating hours and use of natural gas rather than coal, resulting in lower expenditures for SCR consumables and maintenance than previously estimated.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-CO-EI, issued May 9, 2005. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $7,165,809.

There are not any O&M costs projected for the period January 2021 through December 2021.

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Project Title: Big Bend Unit 2 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $8,118,899 compared to the original projection of $8,127,778.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $252,179 compared to the original projection of $329,616, resulting in a variance of -23.5 percent. This variance is due to Big Bend Unit 2 operating for fewer hours than originally projected. As a result, less maintenance is required.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-CO-EI, issued May 9, 2005. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $7,893,828.

The estimated O&M costs for the period January 2021 through December 2021 are $122,020.

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Project Title: Big Bend Unit 3 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $6,610,540 compared to the original projection of $6,617,819.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $457,095 compared to the original projection of $716,027, resulting in a variance of -36.2 percent. This variance is due to Big Bend Unit 3 operating for fewer hours than originally projected. As a result, less maintenance is required.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0502-CO-EI, issued May 9, 2005. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $6,429,857.

The estimated O&M costs for the period January 2021 through December 2021 are $524,097.

Tampa Electric Company
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Project Title: Big Bend Unit 4 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times. The installation of cost-effective SCR technology on the generating units was necessary to meet NO_x emissions requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $5,300,112 compared to the original projection of $5,306,154.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $727,138 compared to the original projection of $968,634, resulting in a variance of -24.9 percent. This variance is due to Big Bend Unit 4 operating for fewer hours than originally projected. As a result, less maintenance is required.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-0986-PAA-EI, issued October 11, 2004. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $5,199,976.

The estimated O&M costs for the period January 2021 through December 2021 are $1,077,230.

Tampa Electric Company
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Project Title: Arsenic Groundwater Standard Program

Project Description:
The Arsenic Groundwater Standard Program that is required by the Environmental Protection Agency and the Department of Environmental Protection became effective January 1, 2005. It requires regulated entities of the State of Florida to monitor the drinking water and groundwater Maximum Contaminant Level ("MCL") for arsenic under the federal rule known as the Safe Drinking Water Act.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2020 through December 2020 are $15,858 compared to the original projection of $0. The variance is due to a site-wide groundwater evaluation recently requested by FDEP as a standard compliance activity. The evaluation was not included in the previous estimate.

Progress Summary: This project was approved by the Commission in Docket No. 20050683-EI, Order No. PSC-2006-0138-PAA-EI, issued February 23, 2006. The project is complete and in service.

Projections: The estimated O&M costs for the period of January 2021 through December 2021 are $36,000.

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Project Title: Big Bend Flue Gas Desulfurization ("FGD") System Reliability

Project Description:
The Big Bend FGD Reliability project is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems at Big Bend Station whenever coal is combusted in the units with few exceptions. The compliance dates for the strictest operational characteristics were January 1, 2011 for Big Bend Unit 3 and January 1, 2014 for Big Bend Units 1 and 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $2,039,210 compared to the original projection of $2,041,735.

Progress Summary: This project was approved by the Commission in Docket No. 20050598-EI, Order No. PSC-2006-0602-PAA-EI, issued July 10, 2006. The project is complete and in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $2,013,174.

Tampa Electric Company
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Project Title: Mercury Air Toxics Standards ("MATS")

Project Description:
In March 2005, the Environmental Protection Agency ("EPA") promulgated the Clean Air Mercury Rule ("CAMR") and was later challenged in court. On February 8, 2008, the Circuit Court of Appeals for the District of Columbia vacated CAMR and ordered a new rule by March 2011. On December 11, 2011, the EPA issued a final version of the rule that applies to all coal and oil-fired electric generating units with a capacity of 25 MW or more and with a compliance deadline is April 16, 2015. The rule sets forth hazardous air pollutant standards ("HAP") for mercury, non-mercury metal HAPs and acid gasses.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $795,655 compared to the original projection of $801,028.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $1,873 compared to the original projection of $27,000, resulting in a variance of -93.1 percent. The variance is due to less contractor services costs required for MATS monitoring activity than originally projected.

Progress Summary: This project was approved by the Commission in Docket No. 20120302-EI, Order No. PSC-2013-0191-PAA-EI, issued May 6, 2013. The project is in service.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is projected to be $783,036.

The estimated O&M costs for the period January 2021 through December 2021 are projected to be $3,000.

Tampa Electric Company
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Project Title: Greenhouse Gas Reduction Program

Project Description:
On September 22, 2009, the EPA enacted a new rule for reporting Greenhouse Gas ("GHG") emissions from large sources and suppliers effective January 1, 2010 in preparation for the first annual GHG report, due March 31, 2011. The new rule is intended to collect accurate and timely emissions data to inform future policy decisions as set forth in the final rule for GHG emission reporting pursuant to the Florida Climate Protection Act, Chapter 403.44 of the Florida Statutes and the docket EPA-HQ-OAR2008-0508-054. The nationwide GHG emissions reduction rule will impact Tampa Electric's generation fleet, components of its transmission and distribution system as well as company service vehicles. According to the rule, the company began collecting greenhouse gas emissions data effective January 1, 2010 to establish a baseline inventory to report to the EPA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M costs for the period January 2020 through December 2020 is $93,149 compared to the original projection of $93,150.

Progress Summary: This project was approved by the Commission in Docket No. 20090508-EI, Order No. PSC-2010-0157-PAA-EI, issued March 22, 2010. The project is complete and in service.

Projections: The estimated O&M costs for the period January 2021 through December 2021 are $93,528.

Tampa Electric Company
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Project Title: Big Bend Gypsum Storage Facility

Project Description:

The Big Bend New Gypsum Storage Facility is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems in order to comply with the CAAA. Gypsum is a by-product of the FGD operations and Tampa Electric had been managing its gypsum inventory through marketing efforts to sell gypsum an existing storage facility. However, the existing storage facility was no longer sufficient to hold the entire gypsum inventory, and Tampa Electric needed an additional storage facility. The new storage facility covers approximately 27 acres and holds approximately 870,000 tons of gypsum.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $2,017,798 compared to the original projection of $2,020,559.

The actual/estimated O&M costs for the period January 2020 through December 2020 are $796,177 compared to the original projection of $947,064, resulting in a variance of -15.9 percent. The variance is due to a reduction in coal generation, compared to the original projection, so the amount of gypsum storage processing is reduced.

Progress Summary: This project was approved by the Commission in Docket No. 20110262-EI, Order No. PSC-2012-0493-PAA-EI, issued September 26, 2012. The project was placed in service in November 2014.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $1,991,084.

The estimated O&M costs for the period January 2021 through December 2021 are $1,177,899.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Coal Combustion Residuals ("CCR") Rule - Phase I & II

Project Description:

On April 17, 2015, the EPA published the CCR Rule with an effective date of October 19, 2015. The new rule requires the safe disposal of CCR in landfills and surface impoundments. Compliance activities include placing fugitive emissions dust control plans, increasing inspections, installing new groundwater monitoring wells, and closure of certain impoundments at CCR regulated management units.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 for Phase I and Phase II is $162,574 and $108,456 compared to the original projections of $185,453 and $59,446, respectively. The variances are due to timing differences in the project schedules when compared to the original projections.

The actual/estimated O&M costs for the period January 2020 through December 2020 for Phase I and Phase II are $6,381 and $14,257,611, respectively, compared to the original projections of $0 and $4,916,092, resulting in variances of 100% and 190%, respectively. The variance for Phase II is due to timing differences in the project schedule when compared to the original projection. The variance for Phase I is due to costs associated with temporary groundwater monitoring wells that were not included in the previous estimate.

Progress Summary: Phase I was approved by the Commission in Docket No. 20150223-EI, Order No. PSC-2016-0068-PAA-EI, issued February 9, 2016. Phase II was approved by the Commission in Docket No. 20170168-EI, Order No. 2017-0483-PAA-EI, issued December 22, 2017.

Projections: Estimated depreciation plus return for the period January 2021 through December 2021 for Phase I and Phase II is $362,933 and $328,169, respectively.

There are not any O&M costs projected for the period January 2021 through December 2021.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Description:

On November 3, 2015, the EPA published the ELG Rule with an effective date of January 4, 2016. The ELG Rule establish limits for wastewater discharges from flue gas desulfurization ("FGD") processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals ("CCR"), gasification processes, and flue gas mercury controls. The final rule requires compliance as soon as possible after November 1, 2020, and no later than December 31, 2023. Tampa Electric hired an engineering consulting firm to perform the Big Bend ELG Compliance Study, completed in 2018, that concluded with a determination of the most appropriate ELG compliance measures identified.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 for Big Bend ELG Compliance is $79,304 compared to the original projection of $145,834. The variance is due to timing differences in the project schedule when compared to the original projection. Project activities have occurred more slowly than originally projected due to permitting delays. FDEP issued its permit regarding the project on April 10, 2020. The project expenditures are still needed and will be incurred in the future.

The actual/estimated O&M costs for the period January 2020 through December 2020 for Big Bend ELG Compliance are $515, compared to $0 in the original projection. The variance is due to more sampling being required to refine wastewater treatment requirements for injectate than previously estimated.

Progress Summary: The Study program was approved by the Commission in Docket No. 20160027-EI, Order No. PSC-2016-0248-PAA-EI, issued June 28, 2016, and it is now complete. The Compliance Project was approved by the Commission in Docket No. 2018007-EI, Order No. PSC-2018-0594-FOF-EI, issued December 20, 2018.

Projections: The ELG Rule Compliance program estimated depreciation plus return for the period January 2021 through December 2021 is $782,650.

The estimated O&M costs projected for the period of January 2021 through December 2021 are $4,800.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2021 through December 2021
Description and Progress Report for
Environmental Compliance Activities and Projects

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

Project Description:

In August 2014, the Environmental Protection Agency ("EPA") published their final rule regarding Section 316(b) of the Clean Water Act. The rule became effective in October 2014. The rule establishes requirements for cooling water intake structures ("CWIS") at existing facilities. Section 316(b) requires that the location, design, construction, and capacity of CWIS reflect the best technology available ("BTA") for minimizing adverse environmental impacts. For this project, compliance activities include modifying the existing Big Bend Unit 1 CWIS to reduce impingement mortality of affected living organisms.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2020 through December 2020 is $31,605, compared to the original projection of $119,004. The variance is due to timing differences in the project schedule when compared to the original projection.

There are no actual/estimated O&M costs for the period January 2020 through December 2020, nor was there an original projection.

Progress Summary: This project was approved by the Commission in Docket No. 2018007-EI, Order No. PSC-2018-0594-FOF-EI, issued December 20, 2018.

Projections: The estimated depreciation plus return for the period January 2021 through December 2021 is $452,502.

There are not any O&M costs projected for the period of January 2021 through December 2021.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2021 to December 2021

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Projected Sales at Meter (MWh)	(3) Effective Sales at Secondary Level (MWh)	(4) Projected Avg 12 CP at Meter (MW)	(5) Demand Loss Expansion Factor	(6) Energy Loss Expansion Factor	(7) Projected Sales at Generation (MWh)	(8) Projected Avg 12 CP at Generation (MW)	(9) Percentage of MWh Sales at Generation (%)	(10) Percentage of 12 CP Demand at Generation (%)	(11) 12 CP & 1/13 Allocation Factor (%)
RS	53.49%	9,684,803	9,684,803	2,067	1.08051	1.05263	10,194,472	2,233	49.67%	58.72%	58.02%
GS, CS	56.42%	902,049	902,049	182	1.08051	1.05261	949,504	197	4.63%	5.18%	5.14%
GSD, SBF	74.99%	7,904,382	7,890,117	1,203	1.07583	1.04913	8,292,733	1,295	40.41%	34.05%	34.54%
IS	145.94%	927,861	911,152	73	1.02893	1.01716	943,787	75	4.60%	1.97%	2.17%
LS1	578.30%	134,246	134,246	3	1.08051	1.05263	141,311	3	0.69%	0.08%	0.13%
TOTAL *		19,553,341	19,522,367	3,528			20,521,807	3,803	100%	100%	100%

Notes:
(1) Average 12 CP load factor based on 2021 Projected calendar data
(2) Projected MWh sales for the period January 2021 to December 2021
(3) Effective sales at secondary level for the period January 2021 to December 2021.
(4) Column 2 / (Column 1 x 8760)
(5) Based on 2021 projected demand losses.
(6) Based on 2021 projected energy losses.
(7) Column 2 x Column 6
(8) Column 4 x Column 5
(9) Column 7 / Total Column 7
(10) Column 8 / Total Column 8
(11) Column 9 x1/13 + Column 10 x 12/13

* Totals on this schedule may not foot due to rounding

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2021 to December 2021

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 1/13 Allocation Factor (%)	(3) Energy-Related Costs ($)	(4) Demand-Related Costs ($)	(5) Total Environmental Costs ($)	(6) Projected Sales at Meter (MWh)	(7) Effective Sales at Secondary Level (MWh)	**(8) Environmental Cost Recovery Factors (¢/kWh)**
RS	49.67%	58.02%	24,752,472	1,305,330	26,057,802	9,684,803	9,684,803	**0.269**
GS, CS	4.63%	5.14%	2,307,307	115,639	2,422,946	902,049	902,049	**0.269**
GSD, SBF	40.41%	34.54%	20,137,858	777,079	20,914,937	7,904,382	7,890,117	
Secondary								**0.265**
Primary								**0.262**
Transmission								**0.260**
IS	4.60%	2.17%	2,292,357	48,821	2,341,178	927,861	911,152	
Secondary								**0.257**
Primary								**0.254**
Transmission								**0.252**
LS1	0.69%	0.13%	343,854	2,925	346,779	134,246	134,246	**0.258**
TOTAL *	100.00%	100.00%	49,833,848	2,249,793	52,083,641	19,553,341	19,522,367	**0.267**

* Totals on this schedule may not foot due to rounding

Notes:
(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 11
(3) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(4) Column 2 x Total Demand Jurisdictional Dollars from Form 42-1P, line 5
(5) Column 3 + Column 4
(6) From Form 42-6P, Column 2
(7) From Form 42-6P, Column 3
(8) Column 5 / (Column 7 x 10)

Form 42 - 8P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2021 to December 2021

Calculation of Revenue Requirement Rate of Return
(in Dollars)

	(1) Jurisdictional Rate Base *2021 Adj. FESR* ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 2,505,932	35.87%	4.33%	1.5517%
Short Term Debt	152,497	2.18%	2.50%	0.0546%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	89,536	1.28%	2.43%	0.0311%
Common Equity	3,076,748	44.04%	10.25%	4.5140%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	969,489	13.88%	0.00%	0.0000%
Deferred ITC - Weighted Cost	192,214	2.75%	7.46%	0.2051%
Total	$ 6,986,416	100.00%		6.36%

ITC split between Debt and Equity:

Long Term Debt	$ 2,505,932	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	3,076,748	Equity - Common	54.00%
Total	$ 5,582,680	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.2051% * 46.00%	0.0943%
Equity = 0.2051% * 54.00%	0.1108%
Weighted Cost	0.2051%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.5140%
Deferred ITC - Weighted Cost	0.1108%
	4.6248%
Times Tax Multiplier	1.32830
Total Equity Component	6.1431%

Total Debt Cost Rate:

Long Term Debt	1.5517%
Short Term Debt	0.0546%
Customer Deposits	0.0311%
Deferred ITC - Weighted Cost	0.0943%
Total Debt Component	1.7317%
	7.8748%

Notes:

Column (1) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
Column (4) - Column (2) x Column (3)

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FPL's response to Staff's First Set of Interrogatories Nos. 1-2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 35
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: FPL's response to Staff's First Set of Interrogatories Nos. 1-2
[Bates Nos. 00001-00003]

QUESTION:
Please refer to FPL's Solar Plant Operation Status Report for November 2019, Document No. 11444-2019. Please explain why the monthly Net Generation for the Martin Solar project is comparatively lower for November 2019 than the other months in the year.

RESPONSE:
The reason for the lower monthly net generation for the Martin Solar project in November 2019 is an error in the daily cumulative generation totals. The correct November monthly net generation for Martin Solar is 1388.29 MWH. A corrected November 2019 Solar Plant Operation Status Report will be included with the February 2020 report to be filed March 20, 2020.

QUESTION:
Please refer to FPL's Solar Plant Operation Status Report for December 2019, Document No. 00435-2020. Page 2 of 3 of the report, for the Martin Solar Plant, shows (10) tons of coal in the Coal Displaced Column. Please explain how the Martin Solar Plant caused FPL to burn 10 tons of coal instead of displacing the coal.

RESPONSE:
In December 2019, the Martin Solar Plant capacity factor was lower than expected due to lower than average solar resource availability. During periods of poor solar resource availability and low ambient temperatures, the Martin Solar Plant must maintain the Heat Transfer Fluid (HTF) temperature in order to maintain required HTF volume in the system. During those periods the HTF fluid is heated using steam from Unit 8 combustion turbines, which increases the power consumption attributed to the plant. This occurred during the December 2019 period. During the days at the Martin solar site where auxiliary power usage is greater than solar power production, the additional generation needed to make up for the auxiliary power usage onsite was provided by the marginal units to meet system load requirements. During the December 2019 period of low solar resource availability the system marginal unit was Scherer Unit 4.

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FPL's response to Staff's Second Set of Interrogatories Nos. 3-14

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 36
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: FPL's response to Staff's Second Set of Interrogatories Nos. 3-14
[Bates Nos. 00004-00016]

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 22 – Pipeline Integrity Management. Please refer to Exhibit RBD-1, page 4 of 71. Please explain the 29.0 percent decrease in Operational and Maintenance (O&M) expenses for Project 22.

RESPONSE:
The amount presented in the 2019 Actual/Estimated true-up filing for the Pipeline Integrity Management Program included costs to improve pipeline depth of cover at Manatee Plant due to marshy conditions in the area. Due to drier weather, the cost was substantially lower because techniques to mitigate the wet conditions, such as timber matting, were not needed.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 24 – Manatee Plant Reburn. Please refer to page 8, lines 1 through 7. Please explain why the inspection and maintenance work was postponed and not completed during the October 2019 outages.

RESPONSE:
The October 2019 outage at the Manatee Plant was deferred as a result of unplanned outages at Martin Units 3&4, Sanford Unit 5 and Okeechobee Unit 1, which necessitated keeping Manatee Units 1 & 2 available to serve load when needed.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 29 – SCR Consumables. Please refer to page 8, lines 17 through 22. Why was the anhydrous ammonia tank maintenance at the Martin site, which was originally planned for 2019, deferred to 2020?

RESPONSE:
The outage for the ammonia storage tank maintenance required that the combustion turbines (CTs) of Martin Unit 8 have operating restrictions to ensure air emission permit limits would not be exceeded while ammonia flow for NOx emission control was not available. The outage was deferred as a result of unplanned outages at Martin Units 3&4, Sanford Unit 5 and Okeechobee Unit 1 that required the Martin Unit 8 CTs be available to serve load.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 37 – DeSoto Solar. Please refer to page 9, lines 1 through 4. What are the additional reliability improvements and maintenance activities at the DeSoto Solar site that caused an increase in O&M activities?

RESPONSE:
The additional reliability activities related to trackers that were repaired (material and labor) and inverter cooling fan replacement.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 48 – Industrial Boiler MACT. Please refer to RBD-1, page 4 of 71. Please explain the 11.1 percent decrease in O&M expenses for Project 48.

RESPONSE:
The O&M decrease was a result of avoided vendor costs associated with the boiler tuning required by the Industrial Boiler MACT at the West County Plant. The vendor was scheduled to be on-site to perform other maintenance work and the plant was able to avoid an additional mobilization and de-mobilization cost for the vendor to travel to the plant to perform the tuning.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 50 – Steam Electric Effluent Guidelines Revised Rules. Please refer to RBD-1, page 4 of 71. Please explain the 21.6 percent increase in the O&M expenses for Project 50.

RESPONSE:
The increase was associated with study related costs, which were originally anticipated to be capitalized. Delays associated with the issuance of a final, revised Steam Electric Effluent Limitations Guidelines Rule delayed capitalization.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 51 – Gopher Tortoise Relocations. Please refer to RBD-1, page 9 of 71. Please explain the 15.7 percent decrease in the O&M expenses for Project 51.

RESPONSE:
The 15.7 percent decrease was due to the Sanford Plant not needing to relocate any gopher tortoises in 2019. The sites only relocate gopher tortoises when necessary.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 54-Coal Combustion Residuals. Please refer to page 10, lines 6 through 10. Please explain why the cost associated with the replacement of a wet bottom ash system with a dry bottom ash system should not have been included in 2019.

RESPONSE:
O&M costs associated with the wet bottom ash handling system were being recovered through base rates. When FPL replaced this system with a dry bottom ash handling system it inadvertently included O&M estimates in ECRC for the new system that should have been assigned to base rates.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 55 – Solar Site Avian Monitoring and Reporting Project. Please refer to RBD-1, page 4 of 71. Please explain the 13.8 percent increase in the O&M expenses for Project 55.

RESPONSE:
The 13.8 percent increase was due to higher than projected costs relating to six additional mortality monitoring events, pre-study carcass clearing survey, and incorporation of additional data into data analysis and reporting efforts needed to finalize the project.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 28 – CWA 316(b) Phase II Rule. Witness Deaton explained the decrease in O&M activities on page 8, lines 9 through 14. Please explain the 20.8 percent decrease in Capital investment for this project referenced at RBD-1, page 9 of 71.

RESPONSE:
In November 2017, FPL installed a horseshoe crab barrier that has proven effective in reducing the number of horseshoe crabs that are impacted by the Cape Canaveral Energy Center cooling water intake structure (CWIS). Based on the success of the horseshoe crab barrier, during the second half of 2019, the Florida Department of Environmental Protection and the Florida Fish and Wildlife Conservation Commission agreed that a horseshoe crab return system would not be required because the current horseshoe crab barrier is sufficiently minimizing horseshoe crab impacts at the CWIS. As a result, the funds allocated to design/build a horseshoe crab return system were no longer needed.

QUESTION:
For the following questions, please refer to FPL witness Deaton's direct testimony and exhibits filed April 1, 2020.

Project 41- Manatee Temporary Heating System. Please refer to Exhibit RBD-1 True-up, tab RAD_ECE_42_8A_All_Projects, Project 41. Please explain why the Depreciation Expense is not consistent for all months. For example, why are the Depreciation Expenses for January and May showing $0? Why do the Depreciation Expenses decrease by 50 percent in July when compared to June? Why do the Depreciation Expenses increase by 71 percent in December when compared to November?

RESPONSE:
Manatee Temporary Heating Systems have been approved in the past for specific recovery periods during the modernization of different plants like Cape Canaveral, Riviera and Port Everglades, or as needed in other plants. Once recovery or specific periods ended, depreciation rates were set to zero and no depreciation expense was accrued. This is why there was no depreciation expense accrued for January 2019. In February the Fort Myers Manatee Heating System went into service and 1/2-month of depreciation expense was accrued at the approved depreciation rate. In May the rate for the Fort Myers depreciation group was inadvertently set to zero and no expense was accrued. This error was corrected in June and an adjustment (equivalent to May depreciation expense) was also accrued. Therefore, the total expense for June was about twice the amount. In December, a Temporary Manatee Heating System for Ft. Lauderdale went into service during the modernization for Dania Beach Energy Center. This heating system was approved with a 44-month amortization schedule since FPL plans to dismantle the system at the time the modernized unit goes into service. The December increase was due to the 1/2-month depreciation expense accrued at 27.27% approved rate for the new heating system.

QUESTION:
For the following question, please refer to FPL witness Sole's direct testimony filed April 1, 2020.

Please refer to Exhibit MWS-3. Witness Sole's testimony discusses the letters received from NOAA (2019) and USFWS (2020) regarding the manatee issues at the Cape Canaveral Energy Center. However, as indicated in Exhibit MWS-3, the manatee issues have been present since 2013. What actions has FPL taken to address the issue since 2013? If no actions have been taken, please explain why.

RESPONSE:
Starting in 2013, FPL has worked with the federal and state agencies to find potential solutions to keep manatees out of the intake wells at Cape Canaveral Energy Center. In 2015, the agencies approved the relocation of the Manatee Temporary Heating System (MTHS) and the sheetpile wall to reduce the water velocity within the intake canal, in order to reduce the likelihood of manatees being impacted by the facility's cooling water intake. This project was completed under Project 41. After the work was completed, FPL continued to find manatees within the intake wells. In 2020, FPL received a new letter (MWS-3) from the USFWS, which required FPL to find different solutions to address the manatee issues that continue at the plant, but which are unrelated to the MTHS.

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FPL's response to Staff's Third Set of Interrogatories Nos. 15-18

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 37
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: FPL's response to Staff's Third Set of Interrogatories Nos. 15-18
[Bates Nos. 00017-00022]

QUESTION:
For the following questions, please refer to FPL's witness Deaton's direct testimony filed July 31, 2020, Exhibit RBD-2 – Appendix 1.

Please refer to Exhibit RBD-2, page 1 of 72, Form: 42-1E and page 2 of 72, Form: 42-2E. Form 42-1E does not reflect the End of Period Total Net True-up as indicated on Form 42-2Eb (Line 11); instead Form 42-1E reflects a total of $0 (Line 3). Please explain this difference and correct the values for Form 42-2Eb (Line 11) and Form 42-1E (Line 3) as may be needed.

RESPONSE:
The reference in Line 3 of Form 42-1E was mislabeled as equaling line 11 of Form 42-2E. Line 3 of Form 42-1E should have been labeled as equaling line 10 of Form 42-2E. Attachment I to this Interrogatory is a revised Form 42-1E that includes the correct reference to line 10 of Form 42-2E.

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

FORM: 42-1E

JANUARY 2020 THROUGH DECEMBER 2020

	2020
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$4,556,972
2. Interest Provision (Form 42-2E, Line 6)	$206,813
3. Sum of Current Period Adjustments (Form 42-2E, Line 10)	$0
4. Actual/Estimated True-up to be refunded/(recovered)	$4,763,785

Florida Power & Light Company
Docket No. 20200007-EI
Staff's 3rd Set of Interrogatories
Interrogatory No. 15
Page 2 of 2

Attachment I

20200007.EI Staff Hearing Exhibits 00019

QUESTION:
For the following questions, please refer to FPL's witness Deaton's direct testimony filed July 31, 2020, Exhibit RBD-2 – Appendix 1.

Please refer to Exhibit RBD-2, page 4 of 72, Form 42-4E-1. Please explain the variance of 19.9 percent for Project 14 – NPDES Permit Fees, 15.6 percent for Project 47- NPDES Permit Removal Requirements, and 12 percent for Project 51 – Gopher Tortoise Relocations.

RESPONSE:
The Project 14 O&M variance of $11,500 is primarily attributed to the Fort Lauderdale Plant National Pollutant Discharge Elimination System (NPDES) annual permit fee, which was not included in the original projection.

The Project 47 O&M variance of $12,643 is primarily attributed to costs associated with the Chlorine Dioxide software evaluation that was not included in the original projections.

The Project 51 O&M variance of $3,083 is due to additional days unexpectedly needed to trap and relocate a gopher tortoise.

QUESTION:
For the following questions, please refer to FPL's witness Deaton's direct testimony filed July 31, 2020, Exhibit RBD-2 – Appendix 1.

Please refer to Exhibit RBD-2, page 9 of 72, Form 42-6E. Please explain the variance of 92 percent for Project 47 – NPDES Permit Renewal Requirements and a negative 31 percent for Project 50- Steam Electric Effluent Guidelines Revised Rules.

RESPONSE:
The Project 47 capital variance of $25,372 is primarily a result of the purchase of an additional chlorine dioxide generator, as well as the purchase of titanium instead of stainless steel for the booster pumps. After conducting a cost-benefit analysis during the design phase of the permanent chlorine dioxide project, FPL concluded that the most efficient and cost-effective way to treat intake cooling water and circulating water for both units would be to purchase two chlorine dioxide generators instead of one. In addition, the most cost-effective source of motive water for the educator used to inject chlorine dioxide as a dissolved gas is seawater. In order to be able to use seawater as a motive water source, the booster pumps and associated materials must be constructed with titanium, which is substantially more expensive than stainless steel. These system design decisions increase the overall projected lifespan of the circulating water chlorine dioxide generation equipment and reduce long-term costs.

The Project 50 capital variance of ($44,478) is primarily a result of a delay in expenditures due to a delay in EPA's promulgation of the final Steam Electric Effluent Limitation Guidelines Rule.

QUESTION:
For the following questions, please refer to FPL's witness Sole's direct testimony filed July 31, 2020.

Please refer to Exhibit MWS-5, FDEP Consent Order, page 13 of 27. The Consent Order indicates that FPL will deposit $1.5 million in an escrow account to finance projects.

a. What is the current balance of the escrow account?

b. What projects were financed through the escrow account?

RESPONSE:

a. The current balance available to finance projects in accordance with Consent Order Paragraph 23.c is $1.5 million. FPL has made the $1.5 million available to FDEP and is following the process established by Rule 62-330.301, Florida Administrative Code, to establish an escrow account.

b. Upon review and approval by FDEP, projects will be approved to utilize the $1.5 million. To date, no projects have been authorized.

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FPL's response to Staff's Fourth Set of Interrogatories Nos. 19-21

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 38
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: FPL's response to Staff's Fourth Set of Interrogatories Nos. 19-21
[Bates Nos. 00023-00026]

QUESTION:
Please refer to FPL's witness Deaton's direct testimony filed August 28, 2020, Exhibit RBD-3, page 109 and 110 of 128, Form 42-5P. Does the estimated O&M expenditure of $19.694 million include the $1.8 million in litigation fees that witness Sole testified to in his direct testimony filed July 31, 2020? If not, please explain why it is not included in the projected O&M amounts.

RESPONSE:
The $1.8 million in litigation fees is estimated to be incurred in August 2020 through May 2021; therefore, the costs are included in both the 2020 Actual/Estimated True-Up filing for $991,584 and the 2021 Projections filing for $812,220.

QUESTION:
Please refer to FPL's witness Sole's direct testimony filed on August 28, 2020, page 5, lines 1 through 4. Witness Sole stated that the estimated total cost of rehabilitating the manatee calf is $250,000 over a three-year period. Will FPL pay the entire rehabilitation cost of $250,000?
a. If not, what is FPL's portion of the total costs?
b. If so, please explain why the rehabilitation costs are not shared with the FWC/USFWS.

RESPONSE:
No. FPL will not pay the entire rehabilitation cost of $250,000.

a. FPL has agreed to pay $210,000 of the $250,000 rehabilitation cost. The remainder of the cost will be covered by SeaWorld.
b. N/A

QUESTION:
Please refer to FPL's response to Staff's Third Set of Interrogatories, number 18.
a. Has the Utility applied for approval with FDEP for any of its projects in connection with Project 42: Turkey Point Cooling Canal Monitoring Plan set forth in the current docket?
b. If so, please identify which projects the Utility has submitted to FDEP for approval and if any of those projects will be funded by the Utility's escrow account.
c. If not, when will the Utility apply for approval?

RESPONSE:

a. Yes, FPL has applied and received FDEP approval for multiple projects in connection with Project 42.
b. FPL has submitted and received FDEP approval for the existing freshening operations, the Barge Basin and Turtle Point restoration project, monitoring well construction (as required), and operation of the Underground Injection Control well. These projects are not funded by the escrow account. The escrow account is intended to fund third-party projects as approved by FDEP and will not be utilized for any of FPL's projects in connection with Project 42.
c. FPL has not yet applied for FDEP approval of the Supplemental Salinity Management Plan (SSMP). FPL will file a permit application for the SSMP by the end of 2020.

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Gulf's response to Staff's First Set of Interrogatories Nos. 1-9

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 39
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Gulf's response to Staff's First Set of Interrogatories Nos. 1-9
[Bates Nos. 00027-00036]

Please refer to GPC witness Hume's direct testimony, Exhibit RLH-1, Schedule4A (page 4 of 46) for the following questions.

1. On Line 1.8, the Schedule displays a decrease of 17.7% for "State NPDES Administration". Please explain why this reduction occurred and the net gain of savings in dollars.

RESPONSE:

The decrease shown on Line 1.8 is associated with the $7,500 Plant Smith Industrial Wastewater Permit Renewal fee that was mistakenly booked to the General Water Quality program rather than the State NPDES Administration line item in December 2019. The journal entry was corrected on June 1, 2020, appropriately booking it to the State NPDES Administration. The decrease shown on Line 1.8 did not result in a net savings.

2. On Line 1.10, the Schedule displays a decrease of 58.2% for "Env Auditing/Assessment." Please explain why this reduction occurred and the net gain of savings in dollars.

RESPONSE:

The decrease shown on Line 1.10 is associated with a reduction in costs associated with Gulf's internal environmental assessments. In 2019 the audit costs were reduced because they were included as part of the integration activities. This caused a one-time reduction that drove the $9,318 clause reduction in 2019.

3. On Line 1.11, the Schedule displays a decrease of 6.9% for "General Solid & Hazardous Waste." Please explain why this reduction occurred and the net gain of savings in dollars.

RESPONSE:

The decrease in costs for the General Solid & Hazardous waste program is primarily due to a vacant position in Gulf's Environmental Services department during the second half of 2019 resulting in a net savings of approximately $67,000. The position responsible for Gulf's SPCC and storage tank compliance program for Gulf's three generation sites will be backfilled in 2020. The additional cost decrease noted in this line item is due to shifting contractor support costs from late 2019 to 2020.

4. On Line 1.12, the Schedule displays a decrease of 3.6% for "Above Ground Storage Tanks." Please explain why this reduction occurred and the net gain of savings in dollars.

RESPONSE:

The variance is primarily due to delaying recoating fuel tank concrete containment areas at Plant Crist from 2019 to 2020. This line item decrease will not result in a net savings because the Crist containment coating will be completed in 2020.

5. On Line 1.24, the Schedule displays a decrease of 7.8% for "Smith Water Conservation." Please explain why this reduction occurred and the net gain of savings in dollars.

RESPONSE:

The variance is primarily due to computer programing and electrical support costs for the Smith underground injection wells being less than originally anticipated during the second half of 2019. This decrease resulted in a net savings of approximately $7,000.

6. On Line 1.26, the Schedule displays a decrease of 35.4% for "Annual NOx Allowance." Please explain why this reduction occurred and the net gain of savings in dollars.

RESPONSE:

The decrease shown on Line 1.26 is associated with Annual NOx Allowances at Plant Scherer Unit 3 (Scherer). Scherer actuals were lower than predicted because the unit did not run as much as originally projected. The net savings is $688.

7. On Line 1.28, the Schedule displays a decrease of 49.3% for "Seasonal NOx Allowance." Please explain why this reduction occurred and the net gain of savings in dollars.

RESPONSE:

Line 1.28 refers to SO2 Allowances, and the reduction in costs shown are a net decrease due to less unit run time for Plants Crist, Daniel, and Scherer than originally projected. The net savings from this decrease is $11,167.

8. On Line 1.29, the Schedule displays an increase of 9.5% for "Scherer Flint Credit – Energy." Please explain why this increase occurred and the net cost of savings in dollars.

RESPONSE:

The "Scherer/Flint Credit-Energy" credit represents the incremental revenue requirement related to the portion of Scherer Unit 3 that was dedicated to the Flint contract through December 2019. The Scherer/Flint credit is calculated in accordance with the provisions of the Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-17-0178-S-EI in consolidated dated May 16, 2017 (2017 Settlement Agreement). The increase of $43,062 in the Scherer/Flint credit is primarily driven by two programs 1) Air Quality Compliance an energy allocated program and 2) Coal Combustion Residuals (CCR) a demand allocated program. The net increase is due to the CCR O&M expense for Groundwater Monitoring being lower than forecasted which was offset by the higher than forecasted expenses in Air Quality Compliance attributed to the Baghouse and Scrubber projects costs. The increase does not result in a net gain of savings.

9. On Line 1.30, the Schedule displays a decrease of 20.4% for "Scherer/Flint Credit – Demand." Please explain why this reduction occurred and the net gain of savings in dollars.

RESPONSE:

See Gulf's response to Staff's First Set of Interrogatories Item No. 8.

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Gulf's response to Staff's Second Set of Interrogatories No. 10

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 40
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Gulf's response to Staff's Second Set of Interrogatories No. 10
[Bates Nos. 00037-00041]

QUESTION:

Please refer to Gulf witness Hume's direct testimony filed July 31, 2020, Exhibit RLH-2, Form 42-4E, for the following questions.

a. Please explain the reason for the operation and maintenance (O&M) cost variance of $14,532 or 5.1 percent less than projected for Air Emissions Fees (O&M Project No. 2).

b. Please explain the reason for the O&M cost variance of $14,441 or 6.2 percent less than projected for Title V (O&M Project No. 3).

c. Please explain the reason for the O&M cost variance of $47,858 or 6.5 percent less than projected for Emission Monitoring (O&M Project No. 5).

d. Please explain the reason for the O&M cost variance of $150,951 or 6.7 percent less than projected for Groundwater Contamination Investigation (O&M Project No. 7).

e. Please explain the reason for the O&M cost variance of $14,516 or 41.5 percent more than projected for State NPDES Administration (O&M Project No. 8).

f. Please explain the reason for the O&M cost variance of $12,412 or 82.7 percent less than projected for Env Auditing/Assessment (O&M Project No. 10).

g. Please explain the reason for the O&M cost variance of $10,860 or 1.1 percent less than projected for General Solid & Hazardous Waste (O&M Project No. 11).

h. Please explain the reason for the O&M cost variance of $13,020 or 7.1 percent more than projected for Above Ground Storage Tanks (O&M Project No. 12).

i. Please explain the reason for the O&M cost variance of $1,288,361 or 7.0 percent less than projected for Air Quality Compliance Program (O&M Project No. 20).

j. Please explain the reason for the O&M cost variance of $11,890 or 24.4 percent less than projected for Smith Water Conservation (O&M Project No. 24).

k. Please explain the reason for the O&M cost variance of $1,725 or 55.9 percent less than projected for Annual NOx Allowances (O&M Project No. 26).

l. Please explain the reason for the O&M cost variance of $5,568 or 78.3 percent less than projected for Seasonal NOx Allowances (O&M Project No. 27).

m. Please explain the reason for the O&M cost variance of $20,583 or 209.3 percent more than projected for SO2 Allowances (O&M Project No. 28).

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RESPONSE:

a. Please explain the reason for the operation and maintenance (O&M) cost variance of $14,532 or 5.1 percent less than projected for Air Emissions Fees (O&M Project No. 2).

The $14,532 decrease is primarily due to Plant Crist's air emission fees being less than originally projected. In 2019 Plant Crist operated less, burned less coal, and burned more natural gas than projected in the energy budget used to estimate the air emission fees.

b. Please explain the reason for the O&M cost variance of $14,441 or 6.2 percent less than projected for Title V (O&M Project No. 3).

The $14,441 decrease is due to reduced support costs associated with Title V permit compliance and permitting.

c. Please explain the reason for the O&M cost variance of $47,858 or 6.5 percent less than projected for Emission Monitoring (O&M Project No. 5).

The $47,858 decrease is due to the Plant Crist continuous emission monitoring costs being less than originally projected. Plant Crist has been able to reduce cost by performing routine compliance checks and additional maintenance in house rather than utilizing a contractor.

d. Please explain the reason for the O&M cost variance of $150,951 or 6.7 percent less than projected for Groundwater Contamination Investigation (O&M Project No. 7).

The $150,951 decrease is primarily due to Gulf excavating impacted soils at the Graceville and Pittman substation sites during 2020 and requesting a No Further Action determination for the sites from Florida Department of Environmental Protection ("FDEP"). The excavation projects have allowed Gulf to decrease projected engineering and design costs for potential groundwater treatment systems for the sites. Additionally, Gulf revised its original projections to incorporate the decrease in travel related costs for the remediation projects due to COVID-19 travel restrictions.

e. Please explain the reason for the O&M cost variance of $14,516 or 41.5 percent more than projected for State NPDES Administration (O&M Project No. 8).

The $14,516 variance is due to the Plant Smith and Plant Scholz NPDES industrial wastewater permit application fees booked in 2020 rather than 2019 as originally anticipated. Gulf originally planned to submit the Scholz permit renewal in late

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2019; however, the application submittal and payment of the associated fee was delayed until 2020. Additionally, as discussed in Gulf's response to Staff's First Set of Interrogatories No. 1, Plant Smith's renewal fee was mistakenly booked to the General Water Quality ECRC program rather than the State NPDES Administration in December 2019, a journal correction entry was made in June 2020.

f. Please explain the reason for the O&M cost variance of $12,412 or 82.7 percent less than projected for Env Auditing/Assessment (O&M Project No. 10).

The $12,412 decrease is associated with a reduction in costs associated with Gulf's internal environmental assessments. Due to the COVID-19 pandemic and associated travel restrictions, the NextEra audit team is not planning to travel to Gulf in 2020. The Gulf audit is tentatively scheduled for the second half of 2021, when travel risks are expected to be lower.

g. Please explain the reason for the O&M cost variance of $10,860 or 1.1 percent less than projected for General Solid & Hazardous Waste (O&M Project No. 11).

The $10,860 decrease is due to Plant Crist's waste disposal costs being less than originally projected.

h. Please explain the reason for the O&M cost variance of $13,020 or 7.1 percent more than projected for Above Ground Storage Tanks (O&M Project No. 12).

The $13,020 variance is primarily due to the district office fuel tank maintenance costs being greater than originally anticipated. Gulf has projected additional cost to replace the overfill valves and line leak detectors on the district office fuel tanks.

i. Please explain the reason for the O&M cost variance of $1,288,361 or 7.0 percent less than projected for Air Quality Compliance Program (O&M Project No. 20).

The majority of the decrease is due to maintenance costs for the Plant Scherer Unit 3 emission control equipment being less than originally projected. The Scherer Unit 3 maintenance overhaul is scheduled for 2021 rather than 2020. In addition, maintenance costs for the Plant Crist scrubber and Crist Unit 6 SCR has been reduced due to plans to convert the units to 100% gas fired generation by the end of 2020. Additionally, the Crist hydrated lime costs are also less than originally anticipated.

j. Please explain the reason for the O&M cost variance of $11,890 or 24.4 percent less than projected for Smith Water Conservation (O&M Project No. 24).

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The $11,890 decrease is primarily due to maintenance costs for the Smith underground injection wells being less than originally anticipated during the first half of 2020.

k. Please explain the reason for the O&M cost variance of $1,725 or 55.9 percent less than projected for Annual NOx Allowances (O&M Project No. 26).

The $1,725 variance is primarily due to a decrease in O&M cost for Annual NOx Allowances associated with Scherer Unit 3. Scherer Unit 3 emissions were lower the first half of 2020 than predicted because the unit did not run as much as originally projected. In addition, the Unit is expected to run less for the remainder of 2020.

l. Please explain the reason for the O&M cost variance of $5,568 or 78.3 percent less than projected for Seasonal NOx Allowances (O&M Project No. 27).

The $5,568 decrease in O&M cost for Seasonal NOx Allowances is associated with Scherer Unit 3 and Daniel Units 1 & 2. Emissions were lower than predicted because the units did not run as much as originally projected. In addition, the units are expected to run less for the remainder of 2020.

m. Please explain the reason for the O&M cost variance of $20,583 or 209.3 percent more than projected for SO2 Allowances (O&M Project No. 28).

SO2 allowances were $20,583 higher than previously projected. The variance is due to an error in calculation of emissions credits during the quarterly true up process. In the 2nd Quarter, Gulf calculated an underestimated ending balance for December 2019 inventory. This resulted in an over correction to the inventory balance in April 2020. This discrepancy was corrected in the 3rd Quarter.

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DEF's response to Staff's First Set of Interrogatories No. 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 41
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: DEF's response to Staff's First Set of Interrogatories No. 1
[Bates Nos. 00042-00047]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20200007-EI

Dated: March 23, 2020

DUKE ENERGY FLORIDA, LLC's RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES (NO. 1)

Duke Energy Florida, LLC ("DEF"), responds to Staff's First Set of Interrogatories to DEF (No. 1), as follows:

INTERROGATORIES

1. For the following question, please refer to the January 2020 Solar Report filed on February 28, 2020, Document No. 01171-2020. For the Lake Placid and Trenton solar projects, please complete the following tables:

Solar Project Name	
	Projected Net Generation (MWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Solar Project Name			
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year			

Solar Project Name				
	CO_2 Reductions (Tons)	Nox Reductions (Tons)	SO_2 Reductions (Tons)	Hg Reductions (lbs)
Projected for a year				

Solar Project Name		
	Projected Peak Day Performance	
Time of Day	Winter Peak Day (kW) (January)	Summer Peak Day (kW) (August)
1:00 AM		
2:00 AM		
3:00 AM		
4:00 AM		
5:00 AM		
6:00 AM		
7:00 AM		
8:00 AM		
9:00 AM		
10:00 AM		
11:00 AM		
12:00 PM		
1:00 PM		
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Response:

	Lake Placid
	Projected Net Generation (MWh)
January	7,140
February	8,060
March	10,930
April	11,520
May	12,180
June	10,400
July	10,630
August	9,950
September	9,210
October	8,590
November	7,460
December	7,020

	Lake Placid		
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year	752,194	1,178	6,860

	Lake Placid			
	CO2 Reductions (Tons)	NOx Reductions (Tons)	SO2 Reductions (Tons)	Hg Reductions (Tons)
Projected for a year	62,795	21	18	0

	Projected Peak Day Performance			
Time of Day	Winter Peak Day (Kw) (January)	Avg Hourly (Kw) (January)	Summer Peak Day (Kw) (August)	Avg Hourly (Kw) (August)
1:00 AM	0.0	0.0	0.0	0.0
2:00 AM	0.0	0.0	0.0	0.0
3:00 AM	0.0	0.0	0.0	0.0
4:00 AM	0.0	0.0	0.0	0.0
5:00 AM	0.0	0.0	0.0	0.0
6:00 AM	0.0	0.0	0.0	0.0
7:00 AM	0.0	0.0	0.0	0.0
8:00 AM	1.4	1.0	5.2	3.6
9:00 AM	29.1	18.4	27.8	24.1
10:00 AM	37.4	24.1	37.7	34.2
11:00 AM	36.9	28.2	36.1	35.0
12:00 PM	35.6	28.2	43.0	35.2
1:00 PM	34.5	25.0	39.4	35.7
2:00 PM	35.1	26.9	43.2	36.7
3:00 PM	36.3	26.6	42.9	35.1
4:00 PM	35.5	26.4	42.9	31.4
5:00 PM	30.7	22.5	21.0	22.5
6:00 PM	2.3	2.9	12.7	15.8
7:00 PM	0.0	0.0	14.4	10.0
8:00 PM	0.0	0.0	1.2	1.7
9:00 PM	0.0	0.0	0.0	0.0
10:00 PM	0.0	0.0	0.0	0.0
11:00 PM	0.0	0.0	0.0	0.0
12:00 AM	0.0	0.0	0.0	0.0

	Trenton
	Projected Net Generation (MWh)
January	11,910
February	13,090
March	17,040
April	19,020
May	20,700
June	18,420
July	17,780
August	16,810
September	15,070
October	15,380
November	12,240
December	10,630

	Trenton		
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year	1,251,041	1,959	11,409

	Trenton			
	CO2 Reductions (Tons)	NOx Reductions (Tons)	SO2 Reductions (Tons)	Hg Reductions (Tons)
Projected for a year	104,441	34	30	0

	Projected Peak Day Performance			
Time of Day	Winter Peak Day (Kw) (January)	Avg Hourly (Kw) (January)	Summer Peak Day (Kw) (August)	Avg Hourly (Kw) (August)
1:00 AM	0.0	0.0	0.0	0.0
2:00 AM	0.0	0.0	0.0	0.0
3:00 AM	0.0	0.0	0.0	0.0
4:00 AM	0.0	0.0	0.0	0.0
5:00 AM	0.0	0.0	0.0	0.0
6:00 AM	0.0	0.0	0.0	0.0
7:00 AM	0.0	0.0	0.0	0.0
8:00 AM	0.0	0.2	3.9	3.2
9:00 AM	37.8	24.9	42.1	29.3
10:00 AM	64.2	39.7	64.9	50.5
11:00 AM	64.2	43.1	69.8	53.6
12:00 PM	61.7	45.9	70.4	56.6
1:00 PM	59.5	45.1	69.3	58.7
2:00 PM	60.1	46.9	69.0	55.9
3:00 PM	62.5	44.8	67.5	53.2
4:00 PM	63.3	47.3	9.6	50.4
5:00 PM	53.6	39.7	12.6	50.8
6:00 PM	4.8	6.5	11.6	43.8
7:00 PM	0.0	0.0	5.6	31.2
8:00 PM	0.0	0.0	1.2	5.2
9:00 PM	0.0	0.0	0.0	0.0
10:00 PM	0.0	0.0	0.0	0.0
11:00 PM	0.0	0.0	0.0	0.0
12:00 AM	0.0	0.0	0.0	0.0

All projected values were developed for use in Docket 20190072-EI to project the performance of the solar plant over a 30-year period. These values use historic years of location specific solar irradiance data to create a projected irradiance year, similar to the development of a "weather normal" year for load forecasting. These projected values are the best available data for the projection of long-term unit performance through the life cycle of the solar power plant but may or may not be realized in any specific calendar year or month.

- Data is provided for the projected year 2020. Forecasted data for any specific future month or year will vary due to changes in anticipated solar plant performance including any plant in-service shakedown and changes in the total DEF system make up and performance.
- In response to the table requesting Peak Day Performance, DEF has (1) adjusted the summer peak-day month to August consistent with DEF's projected summer peak; and (2) provided data for the specific day, which aligns with the projected peak for each month as well as the more representative value of the average for the peak month.

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DEF's response to Staff's Second Set of Interrogatories Nos. 2-4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 42
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: DEF's response to Staff's Second Set of Interrogatories Nos. 2-4
[Bates Nos. 00048-00055]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20200007-EI

Dated: June 2, 2020

DUKE ENERGY FLORIDA, LLC's RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 2-4)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Second Set of Interrogatories to DEF (Nos. 2-4), as follows:

INTERROGATORIES

2. For the following questions, please refer to witness Menendez's direct testimony filed April 1, 2020, Exhibit CAM-1, Form 42-4A.

   a. Please explain the reason for the operation and maintenance (O&M) cost variance of $30,479 or 8 percent for the Phase II Cooling Water Intake 316(b) – Intm (Project 6a).
   b. Please explain the reason for the O&M cost variance of $148,523 or 2 percent lower than projected for the Clean Air Interstate Rule/Clean Air Mercury Rule (CAIR/CAMR) Crystal River – Energy (Project 7.4).
   c. Please explain the reason for the O&M cost variance of $8,343 or 9 percent lower than projected for the CAIR/CAMR Crystal River – A&G (Project 7.4).

Response:

2(a): Reviewing, updating, and editing the draft 316b reports in preparation for peer review required additional iterations of report analysis and review due to issues associated with some specific biologic, engineering, and economic components referenced in the reports. This resulted in additional consultant time and materials to ensure complete and accurate report information.

2(b): The O&M cost variance for the Clean Air Interstate Rule/Clean Air Mercury Rule (CAIR/CAMR) Crystal River – Energy (Project 7.4) represents the forecast vs. actual costs for reagents. The total original forecast for reagents was $8,070,700, and actuals came in at $7,922,177, a lower than 2% variance. This slight favorability was primarily due to lower than forecasted Limestone expense.

2(c): The O&M cost variance of $8,343 or 9 percent lower than projected for the CAIR/CAMR Crystal River – A&G (Project 7.4) represents slightly less than forecasted labor associated with A&G being charged to the ECRC recoverable account.

3. Please refer to witness McDaniel's direct testimony filed April 1, 2020, page 6, lines 5-9. Please explain why costs that were originally planned to occur in 2020 were "pulled forward into 2019."

Response:

3. Bartow WET testing was conducted in early 2019 in order to obtain FDEP approval for the use of an antifouling agent. These costs totaling $7,733 were charged to ECRC in 2019. It was subsequently determined that the initial WET tests costs of $7,733 required to obtain approval for the use of the antifouling agent should not have been charged to ECRC due to the fact that they were not part of the routine annual WET testing. DEF identified the erroneous charge in February 2020 and a credit of $7,733 was applied to NPDES Project (Project 16). DEF Witness McDaniel's testimony incorrectly identified this as a timing variance caused by pulling forward 2020 expenses into 2019; DEF will file errata to correct witness McDaniel's testimony.

4. Please refer to the March 2020 Solar Report filed on April 23, 2020, Document No. 02164-2020 for the following question. For the Columbia solar project, please complete the following tables.

Solar Project Name	
	Projected Net Generation (MWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Solar Project Name			
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year			

Solar Project Name				
	CO_2 Reductions (Tons)	Nox Reductions (Tons)	SO_2 Reductions (Tons)	Hg Reductions (lbs)
Projected for a year				

20200007.EI Staff Hearing Exhibits 00050

Solar Project Name		
	Projected Peak Day Performance	
Time of Day	Winter Peak Day (kW) (January)	Summer Peak Day (kW) (August)
1:00 AM		
2:00 AM		
3:00 AM		
4:00 AM		
5:00 AM		
6:00 AM		
7:00 AM		
8:00 AM		
9:00 AM		
10:00 AM		
11:00 AM		
12:00 PM		
1:00 PM		
2:00 PM		
3:00 PM		
4:00 PM		
5:00 PM		
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11:00 PM		
12:00 AM		

Response:

4. Please refer to the March 2020 Solar Report filed on April 23, 2020, Document No. 02164-2020 for the following question. For the Columbia solar project, please complete the following tables.

   See attachment for tables.

20200007.EI Staff Hearing Exhibits 00051

3. Please refer to the March 2020 Solar Report filed on April 23, 2020, Document No. 02164-2020 for the following question. For the Columbia solar project, please complete the following tables.

Solar Project Name	
	Projected Net Generation (MWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Solar Project Name			
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year			

Solar Project Name				
	CO_2 Reductions (Tons)	Nox Reductions (Tons)	SO_2 Reductions (Tons)	Hg Reductions (lbs)
Projected for a year				

Solar Project Name		
	Projected Peak Day Performance	
Time of Day	Winter Peak Day (kW) (January)	Summer Peak Day (kW) (August)
1:00 AM		
2:00 AM		
3:00 AM		
4:00 AM		
5:00 AM		
6:00 AM		
7:00 AM		
8:00 AM		

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9:00 AM		
10:00 AM		
11:00 AM		
12:00 PM		
1:00 PM		
2:00 PM		
3:00 PM		
4:00 PM		
5:00 PM		
6:00 PM		
7:00 PM		
8:00 PM		
9:00 PM		
10:00 PM		
11:00 PM		
12:00 AM		

Response:

Columbia	
	Projected Net Generation (MWh)
January	12,840
February	13,230
March	18,360
April	19,850
May	21,700
June	19,540
July	19,390
August	18,150
September	16,600
October	17,040
November	13,730
December	11,590

Columbia			
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year	1,495,101	10,394	7,068

Columbia				
	CO_2 Reductions (Tons)	Nox Reductions (Tons)	SO_2 Reductions (Tons)	Hg Reductions (lbs)
Projected for a year	112,250	72	20	0

	Projected Peak Day Performance			
Time of Day	Winter Peak Day (Kw) (January)	Avg Hourly (Kw) (January)	Summer Peak Day (Kw) (August)	Avg Hourly (Kw) (August)
1:00 AM	0.0	0.0	0.0	0.0
2:00 AM	0.0	0.0	0.0	0.0
3:00 AM	0.0	0.0	0.0	0.0
4:00 AM	0.0	0.0	0.0	0.0
5:00 AM	0.0	0.0	0.0	0.0
6:00 AM	0.0	0.0	0.0	0.0
7:00 AM	0.0	0.0	0.0	0.0
8:00 AM	0.0	0.0	6.6	4.6
9:00 AM	39.1	23.9	52.9	37.0
10:00 AM	67.5	41.2	72.9	56.4
11:00 AM	68.4	49.0	72.6	60.8
12:00 PM	65.3	48.7	29.0	59.8
1:00 PM	63.2	48.4	56.2	63.8
2:00 PM	63.2	52.2	56.6	59.7
3:00 PM	67.4	50.1	56.3	56.6
4:00 PM	69.2	52.0	51.0	56.6
5:00 PM	53.3	41.2	10.4	49.1
6:00 PM	4.1	7.5	25.3	44.3
7:00 PM	0.0	0.0	56.5	30.4
8:00 PM	0.0	0.0	10.5	6.5
9:00 PM	0.0	0.0	0.0	0.0
10:00 PM	0.0	0.0	0.0	0.0
11:00 PM	0.0	0.0	0.0	0.0
12:00 AM	0.0	0.0	0.0	0.0

All projected values were developed for use in Docket 20180149-EI to project the performance of the solar plant over a 30-year period. These values use historic years of location specific solar irradiance data to create a projected irradiance year, similar to the development of a "weather normal" year for load forecasting. These projected values are the best available data for the projection of long-term unit performance through the life cycle of the solar power plant but may or may not be realized in any specific calendar year or month.

- Data is provided for the first projected full year of operation. Forecasted data for any specific future month or year will vary due to changes in anticipated solar plant performance including any plant in-service shakedown once placed in-service and changes in the total DEF system make up and performance.
- In response to the table requesting Peak Day Performance, DEF has (1) adjusted the summer peak-day month to August consistent with DEF's projected summer peak; and (2) provided data for the specific day which aligns with the projected peak for each month as well as the more representative value of the average for the peak month.

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DEF's response to Staff's Third Set of Interrogatories Nos. 5-6

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 43
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: DEF's response to Staff's Third Set of Interrogatories Nos. 5-6
[Bates Nos. 00056-00060]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20200007-EI

Dated: August 10, 2020

DUKE ENERGY FLORIDA, LLC's RESPONSE TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 5-6)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Third Set of Interrogatories to DEF (Nos. 5-6), as follows:

INTERROGATORIES

5. Please refer to DEF's July 1, 2020 filing (Document No. 03475-2020) related to the new Section 316(b) of the Clean Water Act - Anclote and Bartow project.

   a. Will DEF be providing an update on this new project in its 2021 Projection Filing? If not, when will an update be provided?
   b. Does DEF anticipate requesting recovery of any Anclote and Bartow 316(b) compliance project costs for 2021? If yes, please provide a description and estimate of these costs.
   c. When does DEF plan to select its final compliance options and provide the Commission with initial project scope details and preliminary cost estimates for the Anclote and Bartow 316(b) compliance project?

Response:

   a. DEF provided an update on this project in DEF Witness Kim McDaniel's July 31, 2020 testimony on page 9 (Docket 20200007-EI). "Once the NPDES permit renewal is issued by the FDEP with the required 316(b) Rule compliance strategies, DEF will provide the Commission an update on the status of the 316(b) Rule compliance strategies for Anclote and Bartow stations in Docket 20210007-EI."

   b. DEF Witness Kim McDaniel addressed this in her July 31, 2020 testimony (Docket 20200007-EI, pages 8-9). "While unlikely, it is possible preliminary engineering and design activities could begin as early as the fourth quarter of 2021 if the final NPDES renewal is issued by FDEP next year. Until review of the proposed options by FDEP has been completed and the NPDES permit renewal is issued with new compliance requirements and schedules, DEF will be unable to determine the nature and extent of compliance activities and associated expenditures for the Anclote and Bartow 316(b) projects."

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c. Please refer to DEF's Response to Interrogatory 5(a) above and DEF Witness Kim McDaniel's July 31, 2020 testimony, pages 7 - 9 (Docket 20200007-EI).

6. Please refer to the May 2020 Solar Report filed on June 25, 2020, (Document No. 03339-2020). For the Debary solar project, please complete the following tables.

Solar Project Name	
	Projected Net Generation (MWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Solar Project Name			
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year			

Solar Project Name				
	CO_2 Reductions (Tons)	Nox Reductions (Tons)	SO_2 Reductions (Tons)	Hg Reductions (lbs)
Projected for a year				

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	DeBary
	Projected Net Generation (MWh)
January	11,680
February	11,470
March	14,610
April	15,510
May	15,980
June	13,900
July	14,290
August	13,900
September	12,660
October	13,140
November	11,250
December	11,440

	DeBary		
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year	981,850	3,577	14,743

	DeBary			
	CO2 Reductions (Tons)	NOx Reductions (Tons)	SO2 Reductions (Tons)	Hg Reductions (Tons)
Projected for a year	96,859	49	38	0

Time of Day	Winter Peak Day (Kw) (January)	Avg Hourly (Kw) (January)	Summer Peak Day (Kw) (August)	Avg Hourly (Kw) (August)
1:00 AM	0.0	0.0	0.0	0.0
2:00 AM	0.0	0.0	0.0	0.0
3:00 AM	0.0	0.0	0.0	0.0
4:00 AM	0.0	0.0	0.0	0.0
5:00 AM	0.0	0.0	0.0	0.0
6:00 AM	0.0	0.0	0.0	0.0
7:00 AM	0.0	0.0	0.0	0.0
8:00 AM	1.4	0.0	1.2	9.1
9:00 AM	26.9	2.1	12.2	34.8
10:00 AM	50.2	9.0	13.7	55.7
11:00 AM	65.1	22.8	15.6	70.2
12:00 PM	73.0	54.9	54.4	68.7
1:00 PM	73.0	35.7	63.9	36.9
2:00 PM	73.0	51.5	73.0	71.6
3:00 PM	45.5	64.7	72.3	65.3
4:00 PM	48.2	51.1	58.5	44.8
5:00 PM	32.5	24.9	38.3	20.2
6:00 PM	5.1	7.3	10.8	8.5
7:00 PM	0.0	0.0	0.0	0.0
8:00 PM	0.0	0.0	0.0	0.0
9:00 PM	0.0	0.0	0.0	0.0
10:00 PM	0.0	0.0	0.0	0.0
11:00 PM	0.0	0.0	0.0	0.0
12:00 AM	0.0	0.0	0.0	0.0

All projected values were developed for use in Docket 20190072-EI to project the performance of the solar plant over a 30-year period. These values use historic years of location specific solar irradiance data to create a projected irradiance year, similar to the development of a "weather normal" year for load forecasting. These projected values are the best available data for the projection of long-term unit performance through the life cycle of the solar power plant but may or may not be realized in any specific calendar year or month.

- Data is provided for the first projected full year of operation. Forecasted data for any specific future month or year will vary due to changes in anticipated solar plant performance, including any plant in-service shakedown once placed in service, and changes in the total DEF system make-up and performance.

- In response to the table requesting Peak Day Performance, DEF has (1) adjusted the summer peak-day month to August consistent with DEF's projected summer peak; and (2) provided data for the specific day which aligns with the projected peak for each month as well as the more representative value of the average for the peak month.

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DEF's response to Staff's Fourth Set of Interrogatories Nos. 7-8

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 44
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: DEF's response to Staff's Fourth Set of Interrogatories Nos. 7-8
[Bates Nos. 00061-00062]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20200007-EI

Dated: September 8, 2020

DUKE ENERGY FLORIDA, LLC's RESPONSE TO STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 7-8)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Fourth Set of Interrogatories to DEF (Nos. 7-8), as follows:

INTERROGATORIES

7. Please refer to witness McDaniel's direct testimony filed July 31, 2020, page 3, lines 20-23, and page 4, lines 1-2. Please provide a description of the work performed by the consultant as a result of the peer review comments.

Response:

Peer review of certain sections of the 316(b) report is a requirement of the 316(b) Rule to ensure that site-specific factors related to entrainment compliance options are properly and accurately evaluated. The work performed by the consultant was to address peer review comments around social and economic cost-benefit models associated with the closed-cycle cooling system retrofit evaluations. After further review and analysis of the peer review comments, it was determined that modifications of the final report were necessary.

The consultant compared the modeling inputs and results utilized by peer reviewers, with those utilized by DEF. Changes were made to the modeling parameters, modeling was re-run, and updates were made to reflect final estimates and conclusions.

Modifications of text, figure modifications, table and appendix for Sections 122.21(r)(10) and 122.21(r)(12) of the final report were necessary to reflect revised estimates and conclusions.

8. Please refer to witness McDaniel's direct testimony filed July 31, 2020, page 3, lines 2-4. Please explain when the costs for the remaining site are expected to be incurred.

Response:

Costs for the remaining site are expected to be incurred during the third and fourth quarters of 2021.

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DEF's response to Staff's Fifth Set of Interrogatories Nos. 9-18

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 45
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: DEF's response to Staff's Fifth Set of Interrogatories Nos. 9-18
[Bates Nos. 00063-00067]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20200007-EI

Dated: October 6, 2020

DUKE ENERGY FLORIDA, LLC's RESPONSE TO STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 9-18)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Fifth Set of Interrogatories to DEF (Nos. 9-18), as follows:

INTERROGATORIES

Please refer to witness McDaniel's direct testimony filed August 28, 2020, for the following questions:

9. Please refer to page 5, lines 6-10. Please explain how the O&M cost estimate of $35,000 was developed.

Response:

The 316(b) rule requires a detailed and extensive evaluation of biological, engineering, and economic site-specific factors for the selection of impingement and entrainment compliance options at Anclote and Bartow Station. Duke Energy Florida anticipates that reviewing agencies may request additional clarification of certain model inputs, assumptions, and results. The $35,000 cost projection is based on potential costs for additional explanatory text, tables and figures, and summary calculations from our consultants. Duke Energy Florida estimates $30,000 to address potential requests for additional information (RAIs) from FDEP associated with impingement compliance option selections. An additional $5,000 was included to address potential RAIs from FDEP associated with economic conclusions regarding entrainment compliance at Anclote and Bartow Station.

10. Please refer to page 5, line 22 through page 6, line 2. Please explain how the O&M cost estimate of $275,000 was developed.

Response:

The $275k projected costs for 2021 are associated with the implementation of Consent Order requirements which include post remediation groundwater monitoring, implementation of a deed restriction for the affected area, and final analysis and reporting of results to the Florida Department of Environmental Protection (FDEP). Of the total $275k estimate, approximately $88k is for additional groundwater sampling, consultant costs for the preparation of a natural attenuation groundwater monitoring plan, preparation

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of reports required by the Consent Order such as the Site Rehabilitation Completion Report, and Semi-annual and Annual status reports. Approximately $125k is projected for costs associated with soil remediation and installation of an engineering control in defined areas of the former North Ash Pond at Crystal River in accordance with applicable criteria contained in the Consent Order. Approximately $62k is estimated for potential future costs associated with consulting fees for activities that may be required by FDEP after their review of submittals required by the Order such as additional changes to reports, field work, analysis, and additional investigation or corrective actions, as well as potential legal fees for the implementation of a deed restriction.

11. Please refer to page 9, lines 3-4. Please explain how the O&M cost estimate of $32,000 was developed.

Response:

The O&M cost estimate of $32,000 was projected using estimates provided by contract laboratories; Anclote WET testing $9,800, Bartow WET testing $10,200, and Crystal River $12,000.

12. Please refer to page 9, lines 8-10. Please explain how the O&M cost estimate of $360,000 was developed.

Response:

DEF's cost estimate of $360K was developed based upon unit projected use and required testing. A forecast is developed to predict the annual usage at each unit, then required MATS testing is forecasted based on that predicted usage pattern. Testing is conducted throughout the year and matched to outage periods when availability allows.

Please refer to witness Hill's direct testimony filed August 28, 2020, for the following question:

13. Please refer to page 2, line 10 through page 3, line 2. Please explain how the O&M and capital cost estimates of $278,000 and $250,000, respectively, were developed.

Response:

The O&M costs were estimated based on historical costs incurred in previous years since the federal CCR Rule inception and assumes there will be no significant change in work scope during 2021. These activities, such as routine mowing and vegetation maintenance, the inspections and associated repairs, as well as costs for groundwater monitoring, have been established and are understood.

The capital cost for the new lined sedimentation basin/ditch area is a preliminary cost estimate, which is subject to change, based on a conceptual design using typical cost data from other projects and construction industry cost data. The total project estimate for this

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work is $1.3M. The cost included in the 2021 forecast assumed a majority of the construction and cost would be complete in 2020 and a relatively small percentage of contingency will remain to be completed to close out the project during the first quarter of 2021. Approximately 20% of the total project cost estimate was assumed for the 2021 spending forecast.

Please refer to witness Swartz's direct testimony filed August 28, 2020, page 2, line 18 through page 3, line 6 for the following questions:

14. Please identify the types of "various services" to be completed by contractors related to DEF's Integrated Clean Air Compliance Program.

Response:

DEF's various services to be completed by contractors are for coal combustion operation services, and environmental monitoring and reporting services, such as repairs to pumps, piping, valves and environmental chemical testing in order to maintain operation for the Flue Gas Desulfurization ("FGD") Scrubber.

15. Please explain how the contractor expense estimates totaling $4.5 million were developed.

Response:

Contractor estimates were based upon prior operational and cost experience. For CAIR programs, this consists of contractors for various repair maintenance such as pumps, valves, piping repairs for the Flue Gas Desulfurization scrubber and environmental testing for the Flue Gas Desulfurization scrubber. For WWT, repairs to the pumps and valves were used in the development of contractor expense estimates.

16. Please explain how the parts and materials estimate of $1.9 million was developed.

Response:

Cost expense estimates were based upon prior operational and cost experience. These parts and material estimates include repairs and material for pumps, motors, piping and valves in order to maintain operation of the Flue Gas Desulfurization scrubber and WasteWater Treatment System.

17. Please explain how the CR5 outage cost estimate of $1.8 million was developed.

Response:

CR5 outage cost estimate was based upon expected repairs necessary for the unit 5 Selective Catalytic Reduction. When the unit enters the planned outage, DEF will perform inspections and will adjust the outage work plan accordingly. This cost estimate is in alignment with previous years major outages supporting the catalytic repairs.

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18. Please explain how the reagent and bi-product cost estimates totaling $6.8 million were developed.

Response:

The amount referenced in testimony and this interrogatory should be $6.3M rather than $6.8M. The schedules and other support are correct, as is the total O&M of $21.6M referenced in testimony, only this one bullet point on Page 3 Line 6 of Jeffrey Swartz's testimony was incorrect. Reagent expense estimates were based upon expected generation of the units, which includes considerations for planned outages and general maintenance. Usage and cost modeling are used to forecast the anticipated usage of each unit, which is then applied to projected reagent costs to develop the expense estimate. The detail cost of each reagent is broken out in Exhibit CAM-5, Form 42-4P, page 10 of 18.

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TECO’s response to Staff's First Set of Interrogatories Nos. 1-2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 46
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: TECO’s response to Staff's First Set of Interrogatories Nos. 1-2
[Bates Nos. 00068-00074]

Please refer to the December 2019 Solar Report filed on January 23, 2020, Document No. 00504-2020.

1. For the Wimauma and Little Manatee River solar projects, please complete the following tables.

Solar Project Name	
	Projected Net Generation (MWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Solar Project Name			
	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Projected for a year			

Solar Project Name				
	CO2 Reductions (Tons)	Nox Reductions (Tons)	SO2 Reductions (Tons)	Hg Reductions (lbs)
Projected for a year				

Solar Project Name		
	Projected Peak Day Performance	
Time of Day	Winter Peak Day (kW) (January)	Summer Peak Day (kW) (July)
1:00 AM		
2:00 AM		
3:00 AM		
4:00 AM		
5:00 AM		
6:00 AM		
7:00 AM		
8:00 AM		
9:00 AM		
10:00 AM		
11:00 AM		
12:00 PM		
1:00 PM		
2:00 PM		
3:00 PM		
4:00 PM		
5:00 PM		
6:00 PM		
7:00 PM		
8:00 PM		
9:00 PM		
10:00 PM		
11:00 PM		
12:00 AM		

A. The data requested for the two solar projects is included in the following tables.

Projected Net Generation:

2020	Projected Net Generation (MWh)	
	Wimauma	Little Manatee River
January	11,540	12,320
February	12,820	13,710
March	16,580	17,520
April	18,800	19,740
May	20,290	20,560
June	16,680	17,650
July	16,450	17,450
August	15,940	16,890
September	13,800	14,520
October	14,330	14,180
November	11,840	12,150
December	10,560	10,550

Projected Fuel Displacement:

2020 Annual Projection	NG Displaced (MCF)	Oil Displaced (Bbl)	Coal Displaced (Ton)
Wimauma	1,317,800	0	41
Little Manatee River	1,373,628	0	43

Projected Emissions Reduction:

2020 Annual Projection	CO2 Reductions (Tons)	Nox Reductions (Tons)	SO2 Reductions (Tons)	Hg Reductions (lbs)
Wimauma	88,019	22.5	26.9	0.08
Little Manatee River	91,748	23.4	28.1	0.08

Projected Peak Day Performance:

Wimauma			
	Projected Peak Day Performance		
Time of Day	Winter Peak Day (kW) (January)	Summer Peak Day (kW) (July)*	Summer Peak Day (kW) (August)*
1:00 AM	-	-	-
2:00 AM	-	-	-
3:00 AM	-	-	-
4:00 AM	-	-	-
5:00 AM	-	-	-
6:00 AM	-	-	-
7:00 AM	-	-	-
8:00 AM	4,690	5,520	2,240
9:00 AM	37,000	37,620	36,880
10:00 AM	61,580	62,140	61,520
11:00 AM	64,100	69,990	62,240
12:00 PM	63,030	73,150	73,540
1:00 PM	61,810	74,760	74,520
2:00 PM	62,220	72,260	74,350
3:00 PM	63,420	64,190	74,570
4:00 PM	63,500	73,770	73,180
5:00 PM	51,840	70,570	69,410
6:00 PM	17,970	62,760	61,580
7:00 PM	-	45,800	43,240
8:00 PM	-	13,970	11,250
9:00 PM	-	-	-
10:00 PM	-	-	-
11:00 PM	-	-	-
12:00 AM	-	-	-

* Tampa Electric's Summer Peak is in August; therefore August Peak Day data has been provided as well as the July data requested.

Projected Peak Day Performance (continued):

Little Manatee River			
	Projected Peak Day Performance		
Time of Day	Winter Peak Day (kW) (January)	Summer Peak Day (kW) (July)*	Summer Peak Day (kW) (August)*
1:00 AM	-	-	-
2:00 AM	-	-	-
3:00 AM	-	-	-
4:00 AM	-	-	-
5:00 AM	-	-	-
6:00 AM	-	-	-
7:00 AM	-	540	-
8:00 AM	11,230	16,670	13,630
9:00 AM	38,940	47,550	46,700
10:00 AM	60,430	65,160	65,290
11:00 AM	61,270	72,180	71,570
12:00 PM	59,670	74,500	70,780
1:00 PM	58,080	74,500	66,220
2:00 PM	58,580	74,500	72,030
3:00 PM	59,760	74,500	74,290
4:00 PM	60,280	74,440	74,500
5:00 PM	50,820	65,490	72,140
6:00 PM	20,100	59,480	65,570
7:00 PM	-	43,030	46,940
8:00 PM	-	18,270	14,480
9:00 PM	-	1,940	-
10:00 PM	-	-	-
11:00 PM	-	-	-
12:00 AM	-	-	-

* Tampa Electric's Summer Peak is in August; therefore August Peak Day data has been provided as well as the July data requested.

2. Please refer to the October 2019 Solar Report filed November 20, 2019, Document No. 11024-2019. On page 2 of the report there is a footnote explaining that no coal was burned in October 2019. Did TECO's SoBRA projects displace all of the Utility's coal in October?

A. No. Tampa Electric had planned maintenance at its Big Bend 4 and Polk 1 facilities in October which limited coal burns.

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TECO’s response to Staff's Second Set of Interrogatories Nos. 3-4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 47
PARTY: STAFF HEARING EXHIBIT
DESCRIPTION: TECO’s response to Staff's Second Set of Interrogatories Nos. 3-4
[Bates Nos. 00075-00079]

3. Please refer to TECO witness Rusk's direct testimony, Exhibit PAR-1, Form 42-4A, for the following questions.

a. Please explain the reason for the operation and maintenance (O&M) cost variance of $23,240 or 17.2 percent less than projected for the Big Bend Units 1 & 2 Flue Gas Desulfurization project (Line 1.d).

b. Please explain the reason for the O&M cost variance of $35,876 or 11.7 percent less than projected for the Big Bend PM Minimization and Monitoring project (Line 1-e.).

c. Please explain the reason for the O&M cost variance of $4,715 or 50.7 percent less than projected for the Big Bend NOX Emissions Reduction project (Line 1-f.).

d. Please explain the reason for the O&M cost variance of $2,275 or 23.3 percent less than projected for the Big Bend Unit 1 Pre-SCR project (Line 1-l.).

e. Please explain the reason for the O&M cost variance of $14,200 or 270 percent more than projected for the Big Bend Unit 2 Pre-SCR project (Line 1-m.).

f. Please explain the reason for the O&M cost variance of $2,185 or 12.5 percent less than projected for the Big Bend Unit 3 Pre-SCR project (Line 1-n.).

g. Please explain the reason for the O&M cost variance of $14,291 or 47.23 percent less than projected for the Clean Water Act Section 316(b) Phase II Study (Project Line 1-o.).

h. Please explain the reason for the O&M cost variance of $13,716 or 304 percent more than projected for the Arsenic Groundwater Standard Program (Line 1-p.).

i. Please explain the reason for the O&M cost variance of $25,706 or 27.4 percent less than projected for the Big Bend 1 SCR project (Line 1-q.).

j. Please explain the reason for the O&M cost variance of $8,069 or 204.3 percent more than projected for the Big Bend CCR Rule – Phase I project (Line 1-x.).

k. Please explain the reason for the O&M cost variance of $3,464 or 11.3 percent more than projected for the Big Bend ELG Compliance project (Line 1-y.).

A. The projections are based on typical annual maintenance costs; however, the need for the maintenance is always determined at or about the time the work is scheduled based on the condition of the equipment. If the work is needed, it will be performed as scheduled. Depending upon conditions found when the work is performed, additional maintenance work may be required. If it is not performed at that time, it may be deferred to a future date when it is required.

Regarding actual expenditures as compared to the projections/previous estimates:

a. Big Bend Units 1 & 2 burned natural gas in 2019, rather than coal. As a result, less maintenance was required for Big Bend Units 1 & 2 Flue Gas Desulfurization.

b. The variance in expenditures associated with the Big Bend PM Minimization and Monitoring project was due to planned outages for Units 3 and 4 that were not included in the estimate. This resulted in fewer hours of unit operation than originally estimated. Due to the reduced operation, less maintenance was needed.

c. The variance in expenditures associated with the Big Bend NO_X Emissions Reduction project was due to planned outages for Units 3 and 4 that were not included in the estimate. This resulted in fewer hours of unit operation than originally estimated. Due to the reduced operation, less maintenance was needed.

d. Upon inspection, it was determined that the Big Bend Unit 1 Pre-SCR project required less maintenance than previously estimated due to Unit 1 running on natural gas rather than coal.

e. Upon inspection, it was determined that the Big Bend Unit 2 Pre-SCR required more maintenance than previously estimated. The maintenance work was related to the repair of the economizer O_2 probes on Unit 2.

f. Upon inspection, it was determined that the Big Bend Unit 3 Pre-SCR project required less maintenance than previously estimated due to Unit 3 burning natural gas rather than coal.

g. The variance in expenditures associated with the Clean Water Act Section 316(b) Phase II Study project is due to delayed final NPDES Permits for the Big Bend and Bayside Power Stations compared to the estimated timeline. The work will be performed once the permits are received.

h. The variance in expenditures associated with the Arsenic Groundwater Standard Program is due to a site-wide groundwater evaluation recently requested by FDEP as a standard compliance activity. The evaluation was not included in the previous estimate.

i. The variance in expenditures associated with the Big Bend Unit 1 SCR project is due to fewer unit operating hours and use of natural gas rather than coal, resulting in lower expenditures for SCR consumables and maintenance than previously estimated.

j. The variance in expenditures associated with the Big Bend CCR Rule – Phase I project is due to costs associated with temporary groundwater monitoring wells that were not included in the previous estimate.

k. The variance in expenditures associated with the Big Bend ELG Compliance project is due to more sampling required to refine wastewater treatment requirements for injectate than previously estimated.

4. Please refer to TECO witness Rusk's direct testimony, Exhibit PAR-1, Form 42-6A. Please explain the reason for the capital investment cost variance of $10,409 or 87.4 percent less than projected for the Big Bend Unit 1 Sec. 316(b) Impingement Mortality project (Line 1-ac.).

A. The variance for Big Bend Unit 1 Section 316(b) Impingement Mortality project is due to a delay in receiving the NPDES permit, which is pending at FDEP. As a result, the timing of capital expenditures has been affected. Once the permit is received, the additional capital expenditures are expected to be made.

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TECO’s response to Staff's Third Set of Interrogatories Nos. 5-6

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200007-EI EXHIBIT: 48
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: TECO’s response to Staff's Third Set of Interrogatories Nos. 5-6
[Bates Nos. 00080-00084]

5. Please refer to TECO witness Sizemore's direct testimony filed July 31, 2020, Exhibit MAS-2, Form 42-4E, for the following questions.

a. Please explain the reason for the operation and maintenance (O&M) cost variance of $89 or 125.6 percent less than projected for the SO2 Emissions Allowances project (Line 1.c).

b. Please explain the reason for the O&M cost variance of $5,994 or 50.0 percent less than projected for the Big Bend NOX Emissions Reduction project (Line 1.f).

c. Please explain the reason for the O&M cost variance of $25,815 or 21.7 percent less than projected for the Bayside SCR and Ammonia project (Line 1.j).

d. Please explain the reason for the O&M cost variance of $5,400 or 50.0 percent less than projected for the Big Bend Unit 1 Pre-SCR project (Line 1.l).

e. Please explain the reason for the O&M cost variance of $4,625 or 42.8 percent less than projected for the Big Bend Unit 2 Pre-SCR project (Line 1.m).

f. Please explain the reason for the O&M cost variance of $5,185 or 43.2 percent less than projected for the Big Bend Unit 3 Pre-SCR project (Line 1.n).

g. Please explain the reason for the O&M cost variance of $11,891 or 29.7 percent less than projected for the Clean Water Act Section 316(b) Phase II Study (Line 1.o).

A. The original projections are based on typical annual maintenance costs; however, the need for the maintenance is always determined at or about the time the work is scheduled based on the condition of the equipment. If the work is needed, it will be performed as scheduled. Depending upon conditions found when the work is performed, additional maintenance work may be required. If it is not performed at that time, it may be deferred to a future date when it is required.

a. The variance in the SO_2 Emissions Allowance project is due to less cogeneration purchases and less SO_2 consumption credits than originally projected. Also, included in the current estimate is a gain on SO_2 auction allowance proceeds that was not originally projected. The re-projection incorporated 6 months of actuals and 6 months of estimated amounts based on the same methodology with the averages based on updated historical amounts.

b. The variance in expenditures associated with the Big Bend NOx Emission project was due to planned outages for Units 3 and 4 that were not included in the original estimate. This resulted in fewer hours of unit operation than originally estimated. Due to the reduced operation, less maintenance was needed.

c. The variance in Bayside SCR and Ammonia project is due to less consumables required than originally expected as a result of SCR units running less than originally estimated. The expenditures were lower as a result.

d. The variance in expenditures associated with Big Bend Unit 1 Pre-SCR is related to less maintenance required. Upon inspection, it was determined that the Big Bend Unit 1 Pre-SCR project equipment required less material and maintenance than originally estimated due to running on natural gas rather than coal. The expenditures were lower as a result.

e. The variance in expenditures associated with Big Bend Unit 2 Pre-SCR is related to less maintenance required. Upon inspection, it was determined that the Big Bend Unit 2 Pre-SCR project equipment required less material and maintenance than originally estimated due to running on natural gas rather than coal. The expenditures were lower as a result.

f. The variance in expenditures associated with Big Bend Unit 3 Pre-SCR is related to less maintenance required. Upon inspection, it was determined that the Big Bend Unit 3 Pre-SCR project equipment required less material and maintenance than originally estimated due to running on natural gas rather than coal. The expenditures were lower as a result.

g. The variance in expenditures associated with the Clean Water Act Section 316(b) Phase II Study is due to timing. The final NPDES permits from FDEP were received later than expected for the Big Bend and Bayside Power Stations compared to the originally estimated timeline. Project activity was delayed as a result.

6. Please refer to TECO witness Sizemore's direct testimony filed July 31, 2020, Exhibit MAS-2, Form 42-6E, for the following questions.

a. Please explain the reason for the capital investment cost variance of $22,879 or 12.3 percent less than projected for the Big Bend CCR Rule - Phase I project (Line 1.z).

b. Please explain the reason for the capital investment cost variance of $49,010 or 82.4 percent more than projected for the Big Bend CCR Rule - Phase II project (Line 1.aa).

A. a. The variance in the capital investment cost for the Big Bend CCR Rule - Phase I project is due to estimated costs associated with temporary groundwater monitoring wells that were not included in the original projection.

b. The variance in the capital investment cost for the Big Bend CCR Rule - Phase II Project is due to timing differences in the project schedule when compared to the original projection. Earlier delays in O&M related project activity associated with landfill availability issues were resolved, and the company was able to secure favorable terms for an expedited CCR disposal transportation schedule. As a result, previously delayed project capital expenditures, such as regrading and berm reconstruction, have moved along at a faster pace as well.

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TECO’s response to Staff's Fourth Set of Interrogatories No. 7

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[Bates Nos. 00085-00086]

7. Please refer to TECO witness Sizemore's direct testimony filed August 28, 2020, Exhibit MAS-3, Document No. 5, for the following questions.

a. Please explain why there are no projected operation and maintenance (O&M) costs for the Big Bend Unit 1 Pre-SCR project (Page 19).

b. Please explain why there are no projected O&M costs for the Big Bend Unit 2 Pre-SCR project (Page 20).

c. Please explain why there are no projected O&M costs for the Big Bend Unit 3 Pre-SCR project (Page 21).

d. Please explain why there are no projected O&M costs for the Big Bend Unit 1 SCR project (Page 23).

A. a. Tampa Electric did not project any O&M costs for Big Bend Unit 1 Pre-SCR for the period of January through December 2021. Big Bend Unit 1 is being modernized and the unit as currently configured was permanently removed from commercial service on June 1, 2020.

b. Tampa Electric did not project any O&M costs for Big Bend Unit 2 Pre-SCR for the period of January through December 2021. This is due to Big Bend Unit 2 running on natural gas rather than coal. As such, minimal maintenance costs, if any, are expected.

c. Tampa Electric did not project any O&M costs for Big Bend Unit 3 Pre-SCR for the period of January through December 2021. This is due to Big Bend Unit 3 running on natural gas rather than coal. As such, minimal maintenance costs, if any, are expected.

d. Please see the company's response to Interrogatory No. 7 (a), above.