FILED 11/7/2018
DOCUMENT NO. 07016-2018
FPSC - COMMISSION CLERK

Docket No. 180007-EI
Comprehensive Exhibit List for Entry into Hearing Record
November 5, 2018

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
	STAFF				
1		Exhibit List	Comprehensive Exhibit List		☑
FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)					
2	Michael W. Sole	MWS-1	FPL Supplemental CAIR/MATS/CAVR Filing.	1, 2, 3	
3	Michael W. Sole	MWS-2	Conceptual Location of Fort Myers Plant Manatee Heating System.	1, 2, 3, 10a	
4	Michael W. Sole	MWS-3	FDEP NPDES Permit for PFM.	1, 2, 3, 10b	
5	Michael W. Sole	MWS-4	PFM Manatee Protection Plan.	1, 2, 3, 10a	
6	Michael W. Sole	MWS-5	Environmental Protection Division of the Georgia Department of Natural Resources Permit NPDES Permit Number GA00035564 for Plant Scherer.	1, 2, 3, 10b	
7	Michael W. Sole	MWS-6	Application for EPD NPDES Permit GA00035564 Renewal for Plant Scherer.	1, 2, 3, 10a, 10b, 10c, 10e	
8	Michael W. Sole	MWS-7	Letter from Georgia Power to Plant Scherer Co-Owners.	1, 2, 3, 10b	
9	Michael W. Sole	MWS-8	Alachua County Development Review Committee Order DR-17-04.	1, 2, 3, 10c	
10	Michael W. Sole	MWS-9	FWC Protocol for Monitoring Avian Mortality at Solar Energy Facilities.	1, 2, 3, 10c	

11	Renae B. Deaton	RBD-1	Environmental Cost Recovery Final True-up January 2017 - December 2017 Commission Forms 42-1A through 42-9A.	1, 2, 3, 4, 5, 6, 7, 8, 10d, 13	
12	Renae B. Deaton	RBD-2	Appendix I - Environmental Cost Recovery Actual/Estimated True-up January 2018 – December 2018 - Commission Forms 42-1E through 42-9E.	1, 2, 3, 4, 5, 6, 7, 8, 10d, 13	
13	Renae B. Deaton	RBD-3	Appendix II – Schedules reflecting calculation of revised Environmental Cost Recovery Final True-up amount January 2017-December 2017.	1, 2, 3, 4, 5, 6, 7, 8, 10d, 13	
14	Renae B. Deaton	RBD-4	Appendix I - Environmental Cost Recovery Projections - January 2019 – December 2019 Commission Forms 42-1P through 42-8P[Appendix II - Calculation of Stratified Separation Factors]. Michael W. Sole to co-sponsor Commission Form 42-5P.	1, 2, 3, 4, 5, 6, 7, 8, 10d, 13	
DUKE ENERGY FLORIDA, INC. (DEF) (DIRECT)					
15	Christopher Menendez	CAM-1	Forms 42-1A - 42-9A January 2017 – December 2017.	1, 2, 3,4 5, 6, 7, 8, 9, 9A, 9B, 13	
16	Christopher Menendez	CAM-2	Capital Program Detail January 2017– December 2017.	1, 2, 3,4 5, 6, 7, 8, 9, 9A, 9B, 13	
17	Christopher Menendez	CAM-3	Forms 42-1E – 42-9E January 2018– December 2018.	1, 2, 3,4 5, 6, 7, 8, 9, 9A, 9B, 13	
18	Christopher Menendez	CAM-4	Capital Program Detail January 2018 – December 2018.	1, 2, 3,4 5, 6, 7, 8, 9, 9A, 9B, 13	
19	Christopher Menendez	CAM-5	Forms 42-1P – 42-8P January 2019– December 2019.	1, 2, 3,4 5, 6, 7, 8, 9, 9A, 9B, 13	
20	Christopher Menendez	CAM-6	Capital Program Detail January 2019 – December 2019.	1, 2, 3,4 5, 6, 7, 8, 9, 9A, 9B, 13	
21	Timothy Hill	CAM-5	Form 42-5P, page 23 of 23.	1, 2, 3, 9A	

22	Jeffrey Swartz	JS-1	Crystal River Clean Air Projects Organizational Chart.	1, 2, 3	
23	Jeffrey Swartz	CAM-5	Form 42-5P, pages 7, 21 and 22 of 23.	1, 2, 3	
24	Patricia Q. West	PQW-1	Integrated Clean Air Compliance Plan.	1, 2, 3	
25	Patricia Q. West	CAM-5	Form 42-5P, pages 1-4 and 6-20 of 23.	1, 2, 3	
TAMPA ELECTRIC COMPANY (TECO) (DIRECT)					
26	Penelope A. Rusk	PAR-1	Final Environmental Cost Recovery Commission Forms 42-1A through 42-9A for the period January 2017 through December 2017.	1, 2, 3, 4, 5, 6, 7, 8, 12A-D, 13	
27	Penelope A. Rusk	PAR-2*[1]	Environmental Cost Recovery Commission Forms 42-1E through 42-9E for the Period January 2018 through December 2018.	1, 2, 3, 4, 5, 6, 7, 8, 12A-D, 13	
28	Penelope A. Rusk	PAR-3*	Environmental Cost Recovery Calculation of Factors and Select Forms for the Period January 2018 through December 2018 Without the Company's Two New Projects.	1, 2, 3, 4, 5, 6, 7, 8, 12A-D, 13	
29	Penelope A. Rusk	PAR-4	Environmental Cost Recovery Forms 42-1P through 42-8P Forms for the Period January 2019 through December 2019.	1, 2, 3, 4, 5, 6, 7, 8, 12A-D, 13	
30	Penelope A. Rusk	PAR-5	Environmental Cost Recovery Calculation of Factors and Select Forms for the Period January 2019 through December 2019 Without the Company's Two New Projects.	1, 2, 3, 4, 5, 6, 7, 8, 12A-D, 13	
GULF POWER COMPANY (GULF) (DIRECT)					

[1] *Testimony of Penelope A. Rusk and Exhibits PAR-2 and PAR3 were revised on July 27, 2018.

31	C. Shane Boyett	CSB-1	Calculation of Final True-up 1/17 – 12/17.	1, 2, 3, 4, 5, 6, 7, 8, 11B, 13, 14	
32	C. Shane Boyett	CSB-2	Calculation of Estimated True-up 1/18 – 12/18.	1, 2, 3, 4, 5, 6, 7, 8, 11B, 13, 14	
33	C. Shane Boyett	CSB-3	Calculation of Projection 1/19 – 12/19.	1, 2, 3, 4, 5, 6, 7, 8, 11B, 13, 14	
34	Richard M. Markey	RMM-1	Schedule 5P - Description and Progress Report of Environmental Compliance Activities and Projects.	1, 2, 3, 11A	
35	Richard M. Markey	RMM-2	316(b) Cooling Water Intake Structure Regulation.	1, 2, 3, 11A	
STAFF – (DIRECT)					
36	Michael W. Sole (1-2, 4-6, 16) Juan E. Enjamio (3) Renae B. Deaton (5, 17)		FPL's response to Staff's First Set of Interrogatories Nos. 1-17. **Additional files contained on Staff Hearing Exhibits CD for No. 3 Supplemental.** *[Bates Nos. 00001-00023]*	1,2,3,4, 10A, 10B	
37	Michael W. Sole		FPL's response to Staff's Third Set of Interrogatories Nos. 20-27. *[Bates Nos. 00024-00035]*	1, 2 ,3, 4, 10A, 10B	
38	Michael W. Sole		FPL's response to Staff's Fourth Set of Interrogatories Nos. 28-31. *[Bates Nos. 00036-00041]*	1, 2 ,3, 4, 10B, 10C, 10D	
39	Michael W. Sole		FPL's response to Staff's Second Request for Production of Documents No. 2. **Confidential DN. 04235-2018** *[Bates Nos. 00042-00042]*	10A	

40	Richard M. Markey		Gulf's response to Staff's First Set of Interrogatories Nos. 1-4. *[Bates Nos. 00043-00048]*	1, 2, 3, 4	
41	Richard M. Markey		Gulf's response to Staff's Second Set of Interrogatories Nos. 5-7. *[Bates Nos. 00049-00053]*	1, 2, 3, 4,	
42	Richard M. Markey		Gulf's response to Staff's Third Set of Interrogatories Nos. 8-9. *[Bates Nos. 00054-00057]*	1, 2 ,3, 4, 11A, 11B	
43	Tim Hill (1) Jeffery Swartz (2-3) Patricia Q. West (4-6)		Duke's response to Staff's First Set of Interrogatories Nos. 1-6. *[Bates Nos. 00058-00065]*	1,2,3,4	
44	Tim Hill (7) Jeffery Swartz (8-10)		Duke's response to Staff's Second Set of Interrogatories Nos. 7-10. *[Bates Nos. 00066-00072]*	1, 2, 3, 4, 9A, 9B	
45	Tim Hill		Duke's response to Staff's Third Set of Interrogatories Nos. 11-12. *[Bates Nos. 00073-00077]*	1,2, 3,4, 9A, 9B	
46	Penelope Rusk		TECO's response to Staff's First Set of Interrogatories Nos. 1-7. *[Bates Nos. 00078-00093]*	1,2,3,4	
47	Penelope Rusk (8-10) Paul Carpinone (11-14)		TECO's response to Staff's Second Set of Interrogatories Nos. 8-14. *[Bates Nos. 00094-00106]*	1, 2, 3, 4, 12A, 12B, 12C, 12D	
48	Paul Carpinone		TECO's response to Staff's Third Set of Interrogatories No. 15-16. *[Bates Nos. 00107-00112]*	3	

HEARING EXHIBITS

Live Exhibit Number	Witness	Party	Description		Moved In/Due Date of Late Filed

49	Sole	OPC	ECR Statute		
50	Sole	OPC	02.12.18 amd 3.5.18 FPL Petitions		
51	Sole	OPC	PSC-11-0553-FOF-EI		
52	Sole	SACE	TPCCMP Project O&M Expenses and Capital Costs		
53	Sole	SACE	DERM Consent Agreement addendum		
54	Sole	SACE	DERM 7.7.2017 letter		
55	Sole	SACE	DERM 7.10.18 letter		
56	Sole	SACE	DERM Consent Agreement Excerpt		
57	Sole	FPL	FPL 10.8.18 letter response to DERM 1.10.18 letter		

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 2
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Michael W. Sole MWS-1

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 20180007-EI
ENVIRONMENTAL COST RECOVERY CLAUSE
FPL SUPPLEMENTAL CAIR/MATS/CAVR FILING
APRIL 2, 2018

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.

CAIR Compliance Project Update:

Status of CAIR (now CSAPR) Rule Revision On November 16, 2015 the EPA proposed the CSAPR Update rule to address interstate transport of air pollution under the 2008 Ozone National Ambient Air Quality Standards ("NAAQS"). The proposed rule significantly reduces ozone season NOx budgets for many states using revised air quality data and updates to unit emission rates following installation of controls. In its final CSAPR ("Update Rule") the EPA removed Florida from the cap-and-trade program as emissions from utility units are now below the significance threshold in downwind ozone nonattainment areas. Several states have challenged the EPA rule and litigation is ongoing in the D.C. Circuit on the Update Rule. 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 are ongoing as needed. Costs for operations and maintenance of equipment associated with CSAPR are still required for installed equipment. The associated projects are described below.

St. Johns River Power Park ("SJRPP") Selective Catalytic Reduction Systems ("SCR") and Ammonia Injection Systems

The construction and installation of SCR and Ammonia Injection Systems at SJRPP were accomplished in 2009 with the controls on units 1 & 2 being placed into service in 2010.

FPL's ownership share of the total CSAPR capital cost for installation of the SCR and Ammonia Injection System through 2017 was $55.02 million and $1.57 for O&M. Projected capital cost and operating expenses associated with the SCR/Ammonia Injection System at SJRPP for 2018 are $0. In January 2018 both SJRPP units were retired from service.

Scherer SCR and Wet Flue Gas Desulfurization ("FGD")

The total capital cost for FPL's share of the construction and installation of the FGD (scrubber) and SCR with Ammonia Injection System on Scherer Unit 4 through 2017 is $362.14 million. FPL estimates its share of the Scherer Unit 4 CSAPR capital costs for projects planned in 2018 to be $2.15 million for replacement of the FGD booster fan hub.

For 2018, FPL has estimated its share of O&M expenses for operation of the SCR, FGD, and common plant facilities supporting the controls at $4.33 million to comply with CSAPR. 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. FPL's ownership share of total capital cost for installation of the SCR and FGD at Scherer through 2017 was $23.08 million.

800 MW Unit Cycling Project

FPL completed construction work associated with this project in 2011 to comply with CSAPR. Total capital costs for the 800 MW unit cycling project at Martin and Manatee plants through 2017 are $94.72 million with total O&M expenses at $7.81 million. Projected 2018 O&M expenses are $0.53 million for treatment of condenser tube fouling and maintenance of associated equipment at the Martin and Manatee 800 MW units.

Continuous Emissions Monitoring System ("CEMS") Plan for Gas Turbines ("GT")

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 neither subject to Acid Rain monitoring requirements nor CSAPR monitoring requirements, so CEMS use has been discontinued. O&M expenses for the CEMS at the GTs were $0.46 million through 2017. There are no future projected capital or operating costs for the GT CEMS associated with this project.

Purchases of Allowances

To comply with the CSAPR program requirements, FPL must evaluate whether it holds sufficient allowances for compliance or needs to purchase allowances. In late 2017 EPA evaluated banked CSAPR allowances and was provided notice that banked pre-2017 vintage allowances could be used in 2017 and later years at a discount ratio established by EPA. Similar to 2016, FPL evaluated that the remaining banked 2015 and 2016 CSAPR allowances would not be required for compliance and pursued their market sale to a third party. These allowances were sold to outside parties in fourth quarter of 2017, resulting in a credit of $119,218 to ECRC project "Amortization of Gains on Sales of Emissions Allowances." Allowance sales in 2016 and 2017 resulted in $769,180 of credits that have helped offset FPL's ECRC expenses.

Actual CAIR/CSAPR capital costs through 2017 were $511.89 million.

CAIR/CSAPR CAPITAL COSTS ($Millions)		
Project	Total Project	2018 Projections
SJRPP-SCR/Ammonia Injection System	$55.02	$0.00
Scherer-SCR/FGD	$362.14	$2.15
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 2017 are $32.91 million.

CAIR/CSAPR O&M EXPENSE ($Millions)		
Project	Total Project	2018 Projections
SJRPP-SCR/Ammonia Injection System	$1.57	$0.00
Scherer-SCR/FGD	$23.08	$4.33
800 MW Unit Cycling – Martin	$4.25	$0.40
800 MW Unit Cycling – Manatee	$3.56	$0.13
CEMS at GTs	$0.46	$0.00

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

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

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 prior to the vacatur of CAMR).

FPL's share of capital costs associated with the Mercury Sorbent Injection System, baghouse and Mercury CEMS on Scherer Unit 4 through 2017 is $114.16 million. For 2018, FPL's share of capital costs for the projects at Scherer Unit 4 is estimated to be $0 as capital replacement of components is not anticipated for 2018. For FPL's co-owned units at SJRPP, the retirement of Units 1 and 2 removes all MATS emission, reporting requirements beginning January 2018 and projected costs are $0. For 2018, projected MATS O&M expenses for Plant Scherer are $2.40 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 ("ESP's") 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 2017 at $209.82 million. Total O&M costs through 2017 are $3.14 million. For 2018, FPL is projecting $0.20 million in capital costs for replacement of ESP components and $0.83 million of O&M expenses for maintenance and operation of the 800 MW ESP project.

Actual MATS capital costs through 2017 are $323.98 million.

MATS CAPITAL COSTS ($Millions)		
Project	**Total Project**	**2018 Projections**
Scherer-Sorbent Injection/Baghouse/ HgCEMS	$114.16	$0.00
800 MW ESP PMR/PMT	$209.82	$0.20

**FPL's share of the project costs*

Actual MATS O&M expenses through 2017 are $19.80 million.

MATS O&M EXPENSE ($Millions)		
Project	**Total Project**	**2018 Projections**
SJRPP-Mercury CEMS	$0.46	$0.00
Scherer-Sorbent Injection/Baghouse/ HgCEMS	$16.21	$2.40
800 MW ESP PMR/PMT	$3.14	$0.83

CAVR / BART Project Update:

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

agreement with the Florida DEP that FPL had complied with the requirements of EPA's Regional Haze requirements. Actual CAVR capital costs through 2017 are $0. Actual CAVR O&M expenses through 2017 are $0.06 million. FPL is projecting $0 of CAVR compliance costs for 2018 and does not anticipate any future compliance costs.

CAVR/BART O&M EXPENSE ($Millions)		
Project	**Total Project**	**2018 Projections**
Reasonable Progress Control Technology Determination	$0.06	$0.00



Notes:

Worst expected conditions:

Wind Speed: max 20MPH from north

Min water temperature: 50F

Min Amb air Temperature: 40F

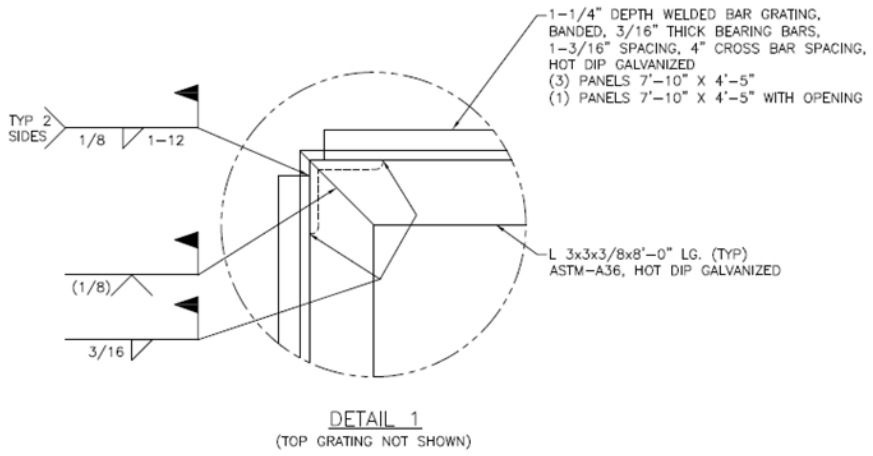
Performance criteria:

Required Area: 100x300 feet

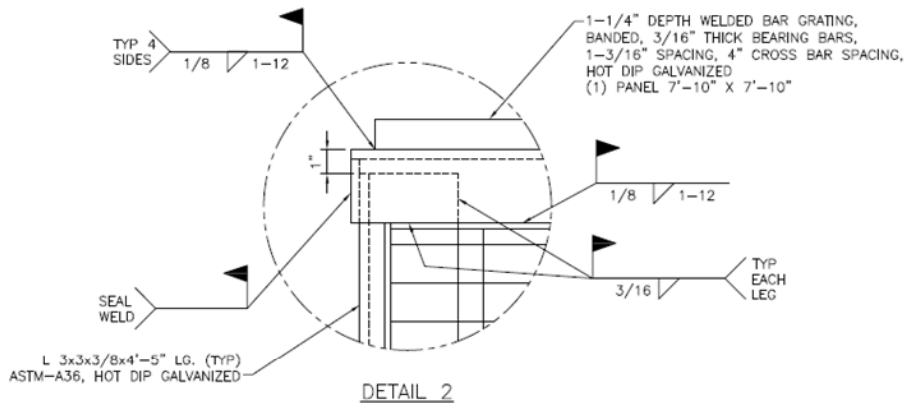
Lowest heated water temp: 68F

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 3
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Michael W. Sole MWS-2

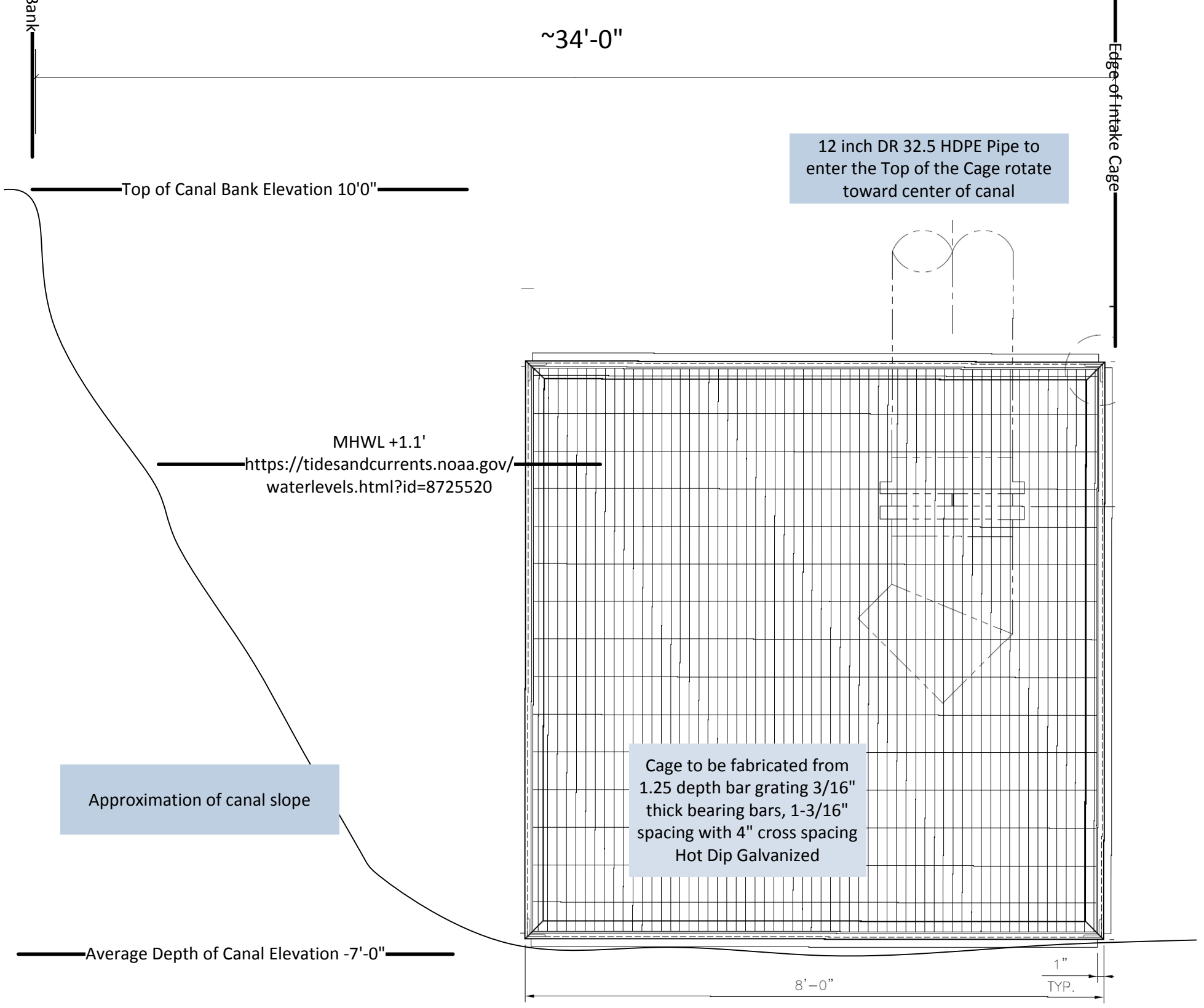
	Discharge Canal Plan General Arrangement			
	Fort Myers Power Plant Canal Heating Concept Drawing			
	SIZE	FSCM NO	DWG NO	REV
	11x17		FT Myers CH 0001	A
	SCALE	NTS	SHEET	1 OF 3



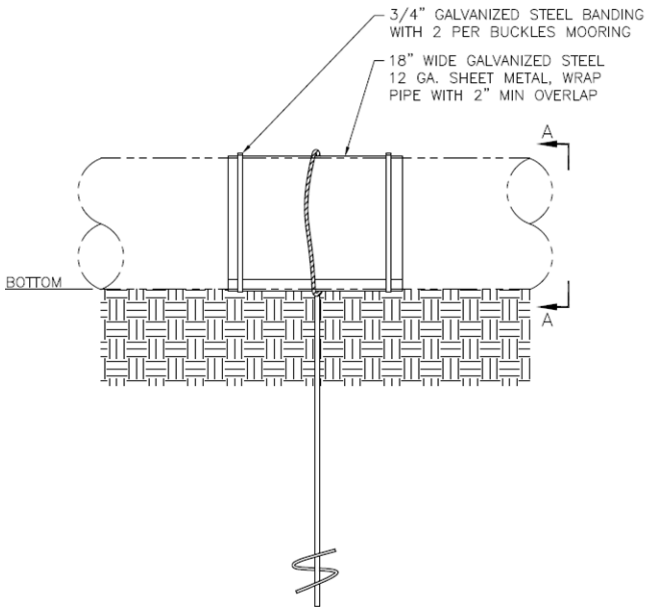
DETAIL 1
(TOP GRATING NOT SHOWN)

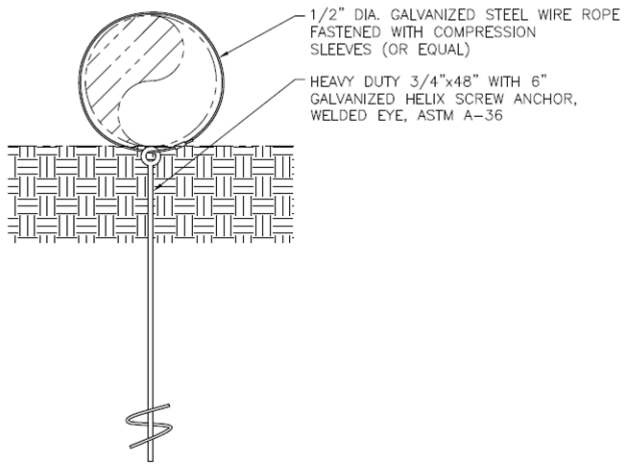


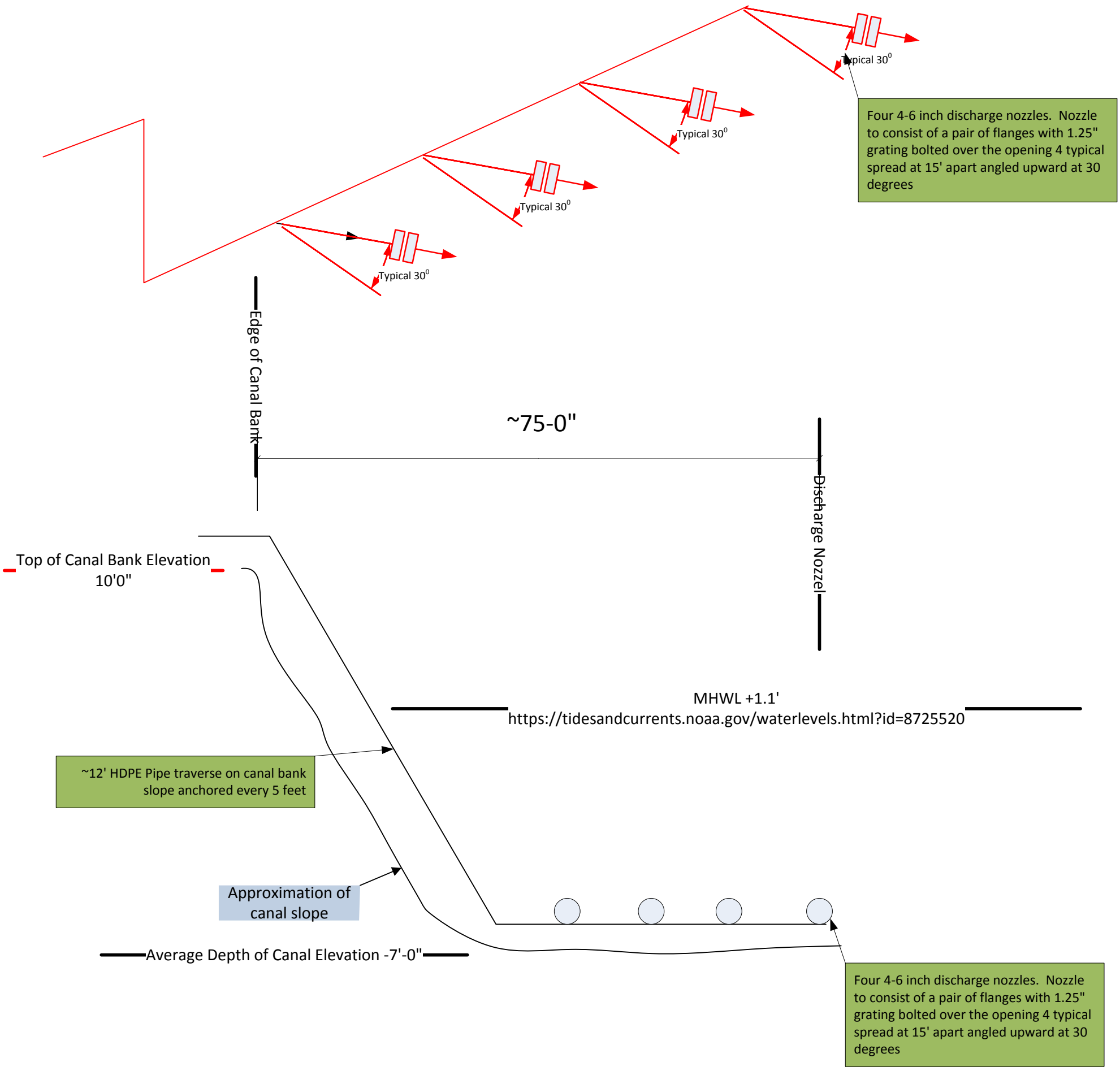
DETAIL 2



	Intake Structure and Pipe section			
	Fort Myers Power Plant Canal Heating Concept Details Drawing			
	SIZE	FSCM NO	DWG NO	REV
			Ft Myers CH Details 0002	A
	SCALE NTS		SHEET	2 OF 3







	Discharge pipe and nozzle section			
	Fort Myers Power Plant Canal Heating Concept Details Drawing			
	SIZE	FSCM NO	DWG NO Ft Myers CH Details 0003	REV A
	SCALE NTS		SHEET 3 OF 3	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 4
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)
(DIRECT)
DESCRIPTION: Michael W. Sole MWS-3

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
BOB MARTINEZ CENTER
2600 BLAIRSTONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

Rick Scott
Governor

Carlos Lopez-Cantera
Lt. Governor

Jonathan P. Steverson
Secretary

Sent by E-mail to:
(Timothy.Panoff@fpl.com)

In the Matter of an
Application for Permit by:

Florida Power & Light Company (FPL)
Mr. Timothy Panoff
Plant General Manager
10650 State Road 80
Fort Myers, FL 33902

Lee County
Fort Myers Plant
NPDES Permit No. FL0001490
File Number FL0001490-008-IW1S

NOTICE OF PERMIT

Enclosed is Permit Number FL0001490 to operate the Fort Myers Plant, issued under Chapter 403, Florida Statutes.

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.

Any party to this order (permit) has the right to seek judicial review of the permit action under Section 120.68, Florida Statutes, by the filing of a notice of appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, 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 30 days from the date when this document is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Elsa A. Potts, P.E.
Program Administrator
Industrial Wastewater Program
Division of Water Resource Management

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52, Florida Statutes, with the designated Deputy Clerk, receipt of which is hereby acknowledged.

Shirley Shields — Clerk
1/20/2016 — Date

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this NOTICE OF DRAFT PERMIT and all copies were mailed before the close of business on 1/20/16 to the listed persons.

Shirley Shields — Name
1/20/2016 — Date

Enclosure

Certified copies furnished by email to:

EPA Region 4 (r4npdespermits@epa.gov)
Karrie-Jo Shell, Power Plant NPDES Permits, EPA Region 4 (shell.karrie-jo@epamail.epa.gov)
Brian Hamman, Chairman, Board of Lee County Commissioner (Dist4@leegov.com)
Timothy Powell, FPL (timothy.powell@fpl.com)
Meghna Pandya, FPL (meghna.pandya@fpl.com)
Gary Maier, P.E., FDEP Ft. Myers (Gary.Maier@dep.state.fl.us)

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:
Florida Power & Light Company

PERMIT NUMBER: FL0001490 (Major)
FILE NUMBER: FL0001490-008-IW1S
ISSUANCE DATE: **January 20, 2016**
EFFECTIVE DATE: **Jauuary 20, 2016**
EXPIRATION DATE: **Jannary 19, 2021**

RESPONSIBLE OFFICIAL:
Timothy Panoff, Plant Manager
10650 State Road 80
Post Office Box 430
Fort Myers, FL 33902
(293)693-4252

FACILITY:

Ft. Myers Power Plant
10650 State Road 80
Post Office Box 430
Fort Myers, FL 33902
Lee County

Latitnde: 26°41' 50" N Longitude: 81°46' 56" 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 constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. This permit does not constitute authorization to discharge wastewater other than as expressly stated in this permit. The above named permittee is hereby authorized to operate the facilities in accordance with the documents attached hereto and specifically described as follows:

FACILITY DESCRIPTION:

The plant consists of six natural gas combined cycle combustion turbines with associated Heat Recovery Steam Generators (HRSGs) and steam turbines with a total generating capacity of 1550 megawatts. There are also twelve gas turbine peaking units that have a combined capacity of 600 megawatts and use No. 2 fuel oil. There are also two peaking combustion turbines that have a combined capacity of 326 megawatts.

The plant has a once-through condenser cooling water system that uses water from the Caloosahatchee River as intake water. The cooling water is routed through the plant condensers and then discharged to the Orange River via the on-site discharge canal. A once-through helper cooling tower is located adjacent to the discharge canal to seasonally reduce the discharge temperature. Boiler blowdown is captured and reused. Reverse osmosis reject is discharged indirectly to the discharge canal via an internal discharge to the cooling tower basin. Metal cleaning wastewater will be disposed of offsite.

WASTEWATER TREATMENT:

Once-through cooling water may be chlorinated to reduce biological fouling in the condensers and intake structures. Dechlorination may be conducted prior to discharge if required. Equipment area storm water and washdown that have the potential to contain oil and grease are routed through an oil/water separator prior to discharge to the storm water basin. The contents of the storm water basin is pumped to the evaporation/percolation basin. In addition, fuel oil storage runoff is routed to an oil/water separator prior to discharge to the evaporation/percolation basin.

REUSE OR DISPOSAL:

Surface Water Discharge D-010: An existing permitted combined discharge to the Orange River (WBID 3240K). The Orange River is a tidally influenced Class III fresh water system at the point of discharge. This combined plant discharge at the end of the 2,500 foot discharge canal is located at approximately at latitude 26° 41' 31" N, longitude 81° 46' 41" W.

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Land Application G-001: An existing land application system (G-001) consisting of an evaporation/percolation pond. The evaporation/percolation pond is located at approximately latitude 26° 41' 38" N, longitude 81° 47' 12" W.

Evaporation/Percolation Emergency Overflow D-020: An existing emergency overflow discharge from the evaporation/percolation pond to the Caloosahatchee River. The discharge is located at approximately latitude 26° 41' 46.7" N, longitude 81° 47' 21.3" W.

Internal Outfalls:

Internal Outfall I-111: An existing internal discharge of once-through cooling water from Unit 1 to the discharge canal.

Internal Outfall I-112: An existing internal discharge of once-through cooling water from Unit 2 to the discharge canal.

Internal Outfall I-113: A new internal discharge of manatee heating water to the discharge canal.

Internal Outfall I-130: An existing internal discharge of reverse osmosis reject water to the cooling tower basin.

Internal Outfall I-170: An existing internal discharge of cooling tower discharge to the discharge canal.

Internal Outfall I-180: An existing internal discharge of auxiliary equipment cooling water to the discharge canal.

Internal Outfall I-190: An existing internal discharge of intake screen wash water to the discharge canal.

Internal Outfall I-1D0: An existing internal discharge of fire pump discharge water to the discharge canal.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in this Cover Sheet and Part I through Part IX on pages 1 through 27 of this permit.

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I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **once-through non-contact cooling water, auxiliary equipment cooling water, intake screen wash water, and reverse osmosis reject water** from **Outfall D-010** to the Orange River. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.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	Report	Monthly Average	6/Day	Recorder	INT-1	
Temperature Rise (ΔT), Water, MODE I	Deg F	Max	Report	Monthly Average	6/Day	Recorder	EFF-1	See I.A.3
Temperature Rise (ΔT), Water, MODE II	Deg F	Max	13.0	Monthly Average	6/Day	Recorder	EFF-1	See I.A.4
Chlorides	mg/L	Max	Report	Daily Maximum	Monthly	Grab	INT-1	
Oxidants, Total Residual	mg/L	Max	0.01	Daily Maximum	Weekly	Grab	EFF-1	See I.A.10
Oxidants, Total Residual	mg/L	Max	0.01	Daily Maximum	Monthly	Grab	EFF-1	See I.A.11
pH	s.u.	Min Max	6.0 8.5	Daily Minimum Daily Maximum	Weekly	Meter	EFF-1	See I.A.12
Temperature, Water	Deg C	Max	Report	Single Sample	Quarterly	Grab	EFF-1, INT-1	See I.A.12
Nitrogen, Total	mg/L	Max	Report	Single Sample	Quarterly	Grab	EFF-1, INT-1	
Phosphorus, Total (as P)	mg/L	Max	Report	Single Sample	Quarterly	Grab	EFF-1, INT-1	
Chronic Whole Effluent Toxicity, 7-Day IC25 (Americamysis bahia)	percent	Min	100	Single Sample	Semi-annually	24-hr Composite	EFF-1	See I.A.14
Chronic Whole Effluent Toxicity, 7-Day IC25 (Menidia beryllina)	percent	Min	100	Single Sample	Semi-annually	24-hr Composite	EFF-1	See I.A.14

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
INT-1	OTCW plant intake.
INT-2	Plant intake screens.
EFF-1	At the end of the discharge canal prior to discharge to the Orange River. Temperature measurements shall be taken at the surface, midpoint, and bottom at the midsection of the canal and averaged.

3. Mode I is applicable each year beginning on January 1 and lasting until the daily average intake temperature first equals or exceeds 74.0°F in the spring. Additionally, Mode I is applicable beginning the day after the daily average intake temperature falls below 74.0°F in the fall and lasting through December 31.

4. Mode II is applicable each year beginning the day after the daily average intake temperature first equals or exceeds 74.0°F and lasting through the day on which the daily average intake temperature first falls below 74.0°F.

5. For partial months in which Mode I ends and Mode II begins (or Mode II ends and Mode I begins) during the middle of the month, the monthly average for each respectively mode shall be calculated based on the number of days the plant was operating in that mode.

6. During the summer months (June, July, and August) and when the steam units are in operation, the permittee shall operate all cells of the cooling tower at all times, regardless of whether the temperature rise is significantly less than the permit limit of 13.0°F . The only exceptions to this requirement are as follows:

   a. In the event of an unavoidable mechanical or electrical failure of a cooling tower component; or

   b. In the event of an unavoidable need to undertake required maintenance of a cooling tower component.

7. The permittee shall maintain current intake traveling screen practices so as to assure that the screens are cycled at least twice during each 24 hours of continuous operation unless precluded by repair or maintenance requirements.

8. The intake through-screen velocity shall be maintained at current levels such that existing maximum velocity is not exceeded.

9. Nothing in this permit authorizes take for the purposes of a Facility's compliance with the federal Endangered Species Act. *[40 CFR 125.98(b)(1)]*

10. Total Residual Oxidants (TRO) means the value obtained using the amperometric titration method for total residual chlorine or the Hach model 19300 or equivalent). Testing for TRO by titration shall be conducted according to either the low-level amperometric method, or the DPD calorimetric method as specified in section 4500-CI E. or 4500 CI G., respectively, Standard Methods for the examination of Water and Waste water, 18th Edition (or most current edition).

    Monitoring requirements for TRO are not applicable if an oxidant has not been added to the non-contact cooling water systems of any electric generating unit during the previous 7 days.

    Multiple grabs for TRO shall be defined as once per five minutes during TRO discharge periods of 30 minutes or less and once per 15 minutes for periods exceeding 30 minutes with no less than four analyses during the period of TRO discharge (sampling shall be continued until the end of the TRO discharge).

11. When only chlorinating Auxiliary Equipment Cooling Water (AECW) sampling for TRO shall be monthly and consists of a single grab sample taken during the middle of the chlorination period. Alternatively, up to three grab samples of AECW, equally spaced within the 2-hour chlorination permit, can be averaged to report on the DMR.

12. Samples for pH and temperature (grab) shall be taken simultaneously with each total ammonia grab sample. Un-ionized ammonia shall be calculated in accordance with the procedure provided by the Department (refer to the website www.dep.state.fl.us./labs/library/index.htm.

    The facility shall submit annual summaries of the quarterly monitoring results sampled at Outfall D-010 as an attachment to EzDMR for the following parameters: Phosphate, Ortho (as PO4); Nitrogen, Ammonia (as N); Ammonia, Total Unionized (as N); Nitrate plus Nitrate, Total (as N); Nitrogen, Kjeldahl, Total (as N); Temperature, Degree C, and pH.

13. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

14. The permittee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from outfall D-010.

    a. Effluent Limitation

(1) In any routine or additional follow-up test for chronic whole effluent toxicity, the 25 percent inhibition concentration (IC25) shall not be less than 100% effluent. *[Rules 62-302.530(61) and 62-4.241(1)(b), F.A.C.]*
(2) For acute whole effluent toxicity, the 96-hour LC50 shall not be less than 100% effluent in any test. *[Rules 62-302.500(1)(a)4. and 62-4.241(1)(a), F.A.C.]*

b. Monitoring Frequency
(1) Routine toxicity tests shall be conducted once every six months, consistent with the existing established schedule and lasting for the duration of this permit.

c. Sampling Requirements
(1) For each routine test or additional follow-up test conducted, a total of three 24-hour composite samples of final effluent shall be collected and used in accordance with the sampling protocol discussed in EPA-821-R-02-014, Section 8.
(2) The first sample shall be used to initiate the test. The remaining two samples shall be collected according to the protocol and used as renewal solutions on Day 3 (48 hours) and Day 5 (96 hours) of the test.
(3) Samples for routine and additional follow-up tests shall not be collected on the same day.

d. Test Requirements
(1) Routine Tests: All routine tests shall be conducted using a control (0% effluent) and a minimum of five test dilutions: **100%, 50%, 25%, 12.5%,** and **6.25%** final effluent.
(2) The permittee shall conduct 7-day survival and growth chronic toxicity tests with a mysid shrimp, **Americamysis (Mysidopsis) bahia**, Method 1007.0, and an inland silverside, **Menidia beryllina**, Method 1006.0, concurrently.
(3) All test species, procedures and quality assurance criteria used shall be in accordance with **Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms**, 3rd Edition, EPA-821-R-02-014. Any deviation of the bioassay procedures outlined herein shall be submitted in writing to the Department for review and approval prior to use. In the event the above method is revised, the permittee shall conduct chronic toxicity testing in accordance with the revised method.
(4) The control water and dilution water used shall be artificial sea salts as described in EPA-821-R-02-014, Section 7.2. The test salinity shall be determined as follows:
(a) For the **Americamysis bahia** bioassays, the effluent shall be adjusted to a salinity of 20 parts per thousand (ppt) with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 20 ppt. If the salinity of the effluent is greater than 20 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.
(b) For the **Menidia beryllina** bioassays, if the effluent salinity is less than 5ppt, the salinity shall be adjusted to 5 ppt with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 5 ppt. If the salinity of the effluent is greater than 5 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.
(c) If the salinity of the effluent requires adjustment, a salinity adjustment control should be prepared and included with each bioassay. The salinity adjustment control is intended to identify toxicity resulting from adjusting the effluent salinity with artificial sea salts. To prepare the salinity adjustment control, dilute the control/dilution water to the salinity of the effluent and adjust the salinity of the salinity adjustment control at the same time and to the same salinity that the salinity of the effluent is adjusted using the same artificial sea salts.

e. Quality Assurance Requirements
(1) A standard reference toxicant (SRT) quality assurance (QA) chronic toxicity test shall be conducted with each species used in the required toxicity tests either concurrently or initiated no more than 30 days before the date of each routine or additional follow-up test conducted. Additionally, the SRT test must be conducted concurrently if the test organisms are obtained from outside the test laboratory unless the test organism supplier provides control chart data from at least the last five monthly chronic toxicity tests using the same reference toxicant and test conditions. If the organism supplier provides the required SRT data, the organism supplier's SRT data and the test laboratory's monthly SRT-QA data shall be included in the reports for each companion routine or additional follow-up test required.

(2) If the mortality in the control (0% effluent) exceeds 20% for either species in any test or any test does not meet "test acceptability criteria", the test for that species (including the control) shall be invalidated and the test repeated. Test acceptability criteria for each species are defined in EPA-821-R-02-014, Section 14.12 (**Americamysis bahia**) and Section 13.12 (**Menidia beryllina**). The repeat test shall begin within 21 days after the last day of the invalid test.
(3) If 100% mortality occurs in all effluent concentrations for either species prior to the end of any test and the control mortality is less than 20% at that time, the test (including the control) for that species shall be terminated with the conclusion that the test fails and constitutes non-compliance.
(4) Routine and additional follow-up tests shall be evaluated for acceptability based on the observed dose-response relationship as required by EPA-821-R-02-014, Section 10.2.6., and the evaluation shall be included with the bioassay laboratory reports.

f. Reporting Requirements
(1) Results from all required tests shall be reported on the Discharge Monitoring Report (DMR) as follows:
(a) Routine and Additional Follow-up Test Results: The calculated IC25 for each test species shall be entered on the DMR.
(2) A bioassay laboratory report for each routine test shall be prepared according to EPA-821-R-02-014, Section 10, Report Preparation and Test Review, and mailed to the Department at the address below within 30 days after the last day of the test.
(3) For additional follow-up tests, a single bioassay laboratory report shall be prepared according to EPA-821-R-02-014, Section 10, and mailed within 30 days after the last day of the second valid additional follow-up test.
(4) Data for invalid tests shall be included in the bioassay laboratory report for the repeat test.
(5) The same bioassay data shall not be reported as the results of more than one test.
(6) All bioassay laboratory reports shall be sent to:

Florida Department of Environmental Protection
South District
2295 Victoria Ave
Suite 364
Ft. Myers, Florida 33901-3875

g. Test Failures
(1) A test fails when the test results do not meet the limits in 14.a.(1).
(2) Additional Follow-up Tests:
(a) If a routine test does not meet the chronic toxicity limitation in 14.a.(1) above, the permittee shall notify the Department at the address above within 21 days after the last day of the failed routine test and conduct two additional follow-up tests on each species that failed the test in accordance with 14.d.
(b) The first test shall be initiated within 28 days after the last day of the failed routine test. The remaining additional follow-up tests shall be conducted weekly thereafter until a total of two valid additional follow-up tests are completed.
(c) The first additional follow-up test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 100%, 50%, 25%, 12.5%, and 6.25% effluent. The permittee may modify the dilution series in the second additional follow-up test to more accurately bracket the toxicity such that at least two dilutions above and two dilutions below the target concentration and a control (0% effluent) are run. All test results shall be analyzed according to the procedures in EPA-821-R-02-014.

(3) In the event of three valid test failures (whether routine or additional follow-up tests) within a 12-month period, the permittee shall notify the Department witbin 21 days after the last day of the third test failure.
(a) The permittee shall submit a plan for correction of the effluent toxicity within 60 days after the last day of the third test failure.
(b) The Department shall review and approve the plan before initiation.
(c) The plan shall be initiated within 30 days following the Department's written approval of the plan.
(d) Progress reports shall be submitted quarterly to the Department at the address above.

(e) During the implementation of the plan, the permittee shall conduct quarterly routine whole effluent toxicity tests in accordance with 14.d. Additional follow-up tests are not required while the plan is in progress. Following completion or termination of the plan, the frequency of monitoring for routine and additional follow-up tests shall return to the schedule established in 14.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-014, a repeat test shall be initiated within 21 days after the last day of the invalid routine test.

(f) Upon completion of four consecutive quarterly valid routine tests that demonstrate compliance with the effluent limitation in 14.a.(1) above, the permittee may submit a written request to the Department to terminate the plan. The plan shall be terminated upon written verification by the Department that the facility has passed at least four consecutive quarterly valid routine whole effluent toxicity tests. If a test within the sequence of the four is deemed invalid, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive quarterly valid routine tests for the purpose of terminating the plan.

(4) If chronic toxicity test results indicate greater than 50% mortality within 96 hours in an effluent concentration equal to or less than the effluent concentration specified as the acute toxicity limit in 14.(a)(2), the Department may revise this permit to require acute definitive whole effluent toxicity testing.

(5) The additional follow-up testing and the plan do not preclude the Department taking enforcement action for acute or chronic whole effluent toxicity failures.

[62-4.241, 62-620.620(3)]

15. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Evaporation/Percolation Pond Emergency Overflow** from **Outfall D-020** to the Caloosahatchee River. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max	Report	Daily Maximum	Weekly Upon Discharge	Estimated	EFF-2	
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Weekly Upon Discharge	Grab	EFF-2	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Weekly Upon Discharge	Grab	EFF-2	

16. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.15. and as described below:

Monitoring Site Number	Description of Monitoring Site
EFF-2	At the end of the evaporation/percolation pond overflow pipe.

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 discharge **once-through non-contact cooling water** from **Outfall I-111** to the discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

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			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Daily	Recording Flow Meter with Totalizer	FLW-1	

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-1	OTCW intake for Unit 1.

3. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **once-through non-contact cooling water** from **Outfall I-112** to the discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Daily	Recording Flow Meter with Totalizer	FLW-2	

4. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.3. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-2	OTCW intake for Unit 2.

5. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **reverse osmosis reject water**[1] from **Outfall I-130** to the cooling tower basin. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max	Report	Daily Maximum	Semi-Annually	Calculated	FLW-3	
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Semi-Annually	Grab	OUI-1	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Semi-Annually	Grab	OUI-1	

6. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.5. and as described below:

[1] When using the Suwannee Aquifer well as source water, discharge of reverse osmosis reject water shall only occur when there is a minimum flow in the discharge canal of 149 MGD.

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Monitoring Site Number	Description of Monitoring Site
FLW-3	The point of discharge to the cooling tower basin (flow measurement).
OUI-1	The point of discharge to the cooling tower basin.

7. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge once-through **cooling tower discharge** from **Ontfall I-170** to the discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Daily	Recorder	FLW-4	
Time of Chlorine Addition	min/day	Max	120	Daily Maximum	Daily	Calculated	OTH-1	
Oxidants, Total Residual	mg/L	Max	0.20	Daily Maximum	Weekly	Grab	OUI-2	See I.B.9

8. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.7. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-4	The cooling tower discharge flume (flow measurement).
OTH-1	The point of chlorine addition to the cooling tower flow.
OUI-2	The cooling tower discharge flume.

9. Total Residual Oxidants (TRO) means the value obtained using the amperometric titration method for total residual chlorine or the Hach model 19300 or equivalent). Testing for TRO by titration shall be conducted according to either the low-level amperometric method, or the DPD calorimetric method as specified in section 4500-CI E. or 4500 CI G., respectively, Standard Methods for the examination of Water and Waste water, 18th Edition (or most current edition).

   Monitoring requirements for TRO are not applicable if an oxidant has not been added to the non-contact cooling water systems of any electric generating unit during the previous 7 days.

   Multiple grabs for TRO shall be defined as once per five minutes during TRO discharge periods of 30 minutes or less and once per 15 minutes for periods exceeding 30 minutes with no less than four analyses during the period of TRO discharge (sampling shall be continued until the end of the TRO discharge).

10. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Anxiliary Equipment Cooling Water (AECW)** from Outfall I-180 to the discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max	Report	Daily Maximum	Weekly	Calculated	FLW-5	
Time of Chlorine Addition	min/day	Max	120	Daily Maximum	Daily	Calculated	OTH-2	

11. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.10 and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-5	AECW intake for Units 1 and 2 (flow measurement).
OTH-2	The point of chlorine addition to AECW.

12. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **manatee heated water** from **Outfall I-113** to the discharge canal via internal outfall I-180. Discharge of the manatee heating water is permitted without limitation or monitoring requirements.

13. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **intake screen wash water** from **Outfall I-190** to the discharge canal. Discharge of intake screen wash water is permitted without limitation or monitoring requirements.

14. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **fire pump discharge** water from **Outfall I-1D0** to the discharge canal. Discharge of fire pump discharge water is permitted without limitation or monitoring requirements.

C. Land Application Systems

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **equipment area stormwater and washdown as well as fuel oil storage runoff** to the **Land Application System G-001**, an evaporation/percolation pond. Occasionally, the runoff may mix with de minimis quantities of process water from minor leaks or spills from the steam generating facilities associated with these units.

   In addition, the permittee is authorized to discharge non-industrial stormwater from Sub-basins 7B and 7C to the evaporation/percolation pond. Discharge to the evaporation/percolation pond is permitted without limitation or monitoring requirements.

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 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 (method detection limits) 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 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 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 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. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	Due Date
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 30	July 28 January 28
Annual	January 1 - December 31	January 28

The permittee may submit either paper or electronic DMR forms. If submitting paper DMR forms, the permittee shall make copies of the attached DMR forms, without altering the original format or content unless approved by the Department, and shall mail the completed DMR forms to the Department by the twenty-eighth (28th) of the month following the month of operation at the address specified below:

Florida Department of Environmental Protection
Water Compliance Assurance Program, Mail Station 3550
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

If submitting electronic DMR forms, the permittee shall use the electronic DMR system (EzDMR) and shall electronically submit the completed DMR forms to the Department by the twenty-eighth (28th) of the month following the month of operation. Data submitted in electronic format is equivalent to data submitted on signed and certified paper DMR forms. *[62-620.610(18)]*

4. 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 South District Office at the address specified below:

Florida Department of Environmental Protection
South District
2295 Victoria Ave
Suite 364
Ft. Myers, Florida 33901-3875

Phone Number - (239)344-5600
FAX Number - (850)412-0590
(All FAX copies and e-mails shall be followed by original copies.)

5. All reports and other information shall be signed in accordance with the requirements of Rule 62-620.305, F.A.C. *[62-620.305]*

6. If there is no discharge from the facility on a day when the facility would normally sample, the sample shall be collected on the day of the next discharge. *[62-620.320(6)]*

7. The permittee is authorized to use only those water treatment chemicals at the frequency and dosage rates described in the permit application and associated documents submitted to the Department for renewal of the current permit. Only one antiscalant chemical shall be used at any given time. Permit revisions are not necessary for use of chemicals equivalent to those being used if the alternative chemicals consist of the same constituents, at the same concentrations and are used at the current rate. The use of other chemicals that are not chemical equivalents or current chemicals at higher dosage rates or frequencies is not authorized and will require a permit revision. 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 described in the permit application.

   The permittee may elect to use products or cleaners other than those listed above, provided the generated wastewater is collected and taken offsite to an approved wastewater treatment facility.

8. 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; 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.A.2, and made available to Department staff upon request. *[62-620.200(26)(a) & (b)]*

9. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream that ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in a permit; except products used for lawn and agricultural purposes or to the nse of herbicides if used in accordance with labeled instructions and any applicable State permit. The permittee shall consult with the Florida Fish and Wildlife Commission, the U.S. Fish and Wildlife Service, and the National Marine Fisheries Service if threatened or endangered species may be exposed to the product.

   In the event the permittee proposes to use biocides, corrosion inhibitors, or additives not authorized in this permit, or not previously reported to the Department, that ultimately may be released to 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 product;

   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-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. EPA registration number, if applicable.

10. The permittee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on August 18, 1999.

11. The permittee shall complete all studies and gather all information required under 40 CFR 122.21(r)(2-13) necessary to establish impingement mortality and entrainment BTA requirements in accordance with the schedule in Permit Condition VI.4.

12. There shall be no discharge of polychlorinated biphenyl (PCB) compounds such as those commonly used for transformer flnid. The permittee shall dispose of all known PCB equipment, articles, and wastes either in accordance with:

    a. Department-issued permits governing soil thermal treatmeut (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)]

II. SLUDGE 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]*

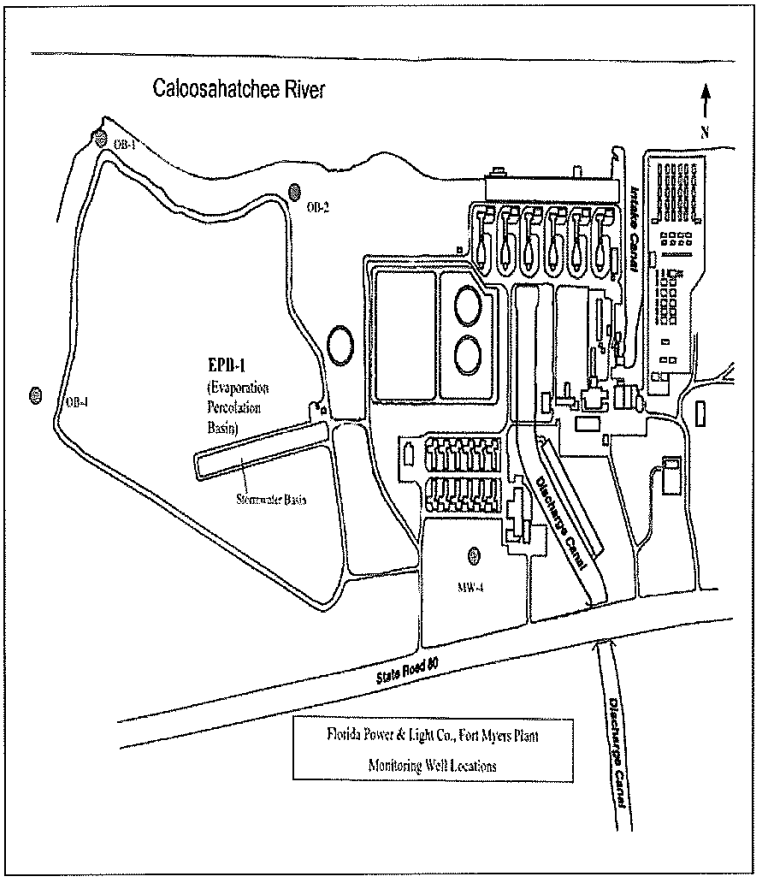
3. Vegetation and materials removed from intake screens and vegetation, sediments and sludge excavated from the settling basins and percolation basins must be properly stored onsite until they are disposed in accordance with requirements in Chapter 62-701, F.A.C., and other applicable State and Federal requirements.

PERMITTEE: Florida Power & Light
FACILITY: Ft. Myers Power Plant

PERMIT NUMBER: FL0001490 (Major)
EXPIRATION DATE: January 19, 2021

III. GROUND WATER REQUIREMENTS

1. The ground water monitoring well locations for this facility are depicted on the site map below as "MW" and "OB":



2. During the period of operation authorized by this permit, the permittee shall sample ground water in accordance with this permit and the approved ground water monitoring plan prepared under Rule 62-522.600, F.A.C.

3. The following monitoring wells shall be sampled for the Fort Myers FP&L Power Plant evaporation/percolation pond, Land Application System G-001.

Monitoring Well ID	Alternate Well Name and/or Description of Monitoring Location	Depth (Feet)	Aquifer Monitored	New or Existing
MW-4 21556	Background Well. Replaces background well MW-3, which was destroyed. Monitor well located along S.R. 80.	20.0	Surficial	Existing
OB-1 21555	Compliance Well. Northwest corner of percolation pond (G-001), between the percolation pond and the Caloosahatchee River.	30.0	Surficial	Existing
OB-2 21554	Intermediate Well. Northeast corner of percolation pond (G-001), between the percolation pond and Caloosahatchee River.	30.0	Surficial	Existing
OB-4 21553	Compliance Well. West of the perc pond (G-001), deep compliance well.	100.0	Surficial	Existing

MWB = Background; MWI = Intermediate; MWC = Compliance, MWP = Piezometer

4. The monitor wells specified in Condition III.B.2 shall be sampled for the parameters listed below:

Parameter Name	Compliance Well Limit	Units	Sample Type	Monitoring Frequency
Specific Conductance	60000.0	umho/cm	Grab	Quarterly
PH	Report	s.u.	Grab	Quarterly
Chloride (as Cl)	Report	mg/L	Grab	Quarterly
Solids, Total Dissolved (TDS)	Report	MG/L	Grab	Quarterly
Water Level Relative to NGVD	Report	FEET	Measured	Quarterly
Sulfate, Total	Report	mg/L	Grab	Quarterly
Nitrogen, Nitrate, Total (as N)	10.0	mg/L	Grab	Quarterly
Carbon, Total Organic (TOC)	Report	mg/L	Grab	Annually
Petroleum Hydrocarbons, Total Recoverable (TRPH)	Report	mg/L	Grab	Annually

5. A zone of discharge is established for G-001, more specifically described as follows:

   The zone of discharge shall not extend further than the limits of the property boundaries as described in the legal description of the property limits for the Fort Myers Florida Power and Light Power Plant, as submitted to the Department on August 28, 1990. The vertical zone of discharge shall not extend below the semi-confining zone at the base of the water table aquifer and is designed to protect the Sandstone Aquifer in that area.

6. The permittee's discharge to ground water shall not cause a violation of water quality standards for ground waters at the boundary of the zone of discharge in accordance with Rules 62-520.400 and 62-520.420, F.A.C.

7. 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., within the zone of discharge.

8. If the concentration for any constituent listed in Permit Condition III.B.4 in the natural background quality of the ground water is greater than the stated maximum, or in the case of pH is also less than the minimum, the representative natural backgrouud quality shall be the prevailing standard.

9. Water levels shall be recorded before evacuating each well for sample collection. Elevation references shall include the top of the well casing and land surface at each well site (NAVD allowable) at a precision of plus or minus 0.01 foot. *[62-520.600(11)(c)]*.

10. Ground water monitoring wells shall be purged prior to sampling to obtain representative samples. *[62-160.210]*.

11. Analyses shall be conducted on unfiltered samples, unless filtered samples have been approved by the Department's South District Office as being more representative of ground water conditions. *[62-520.310(5)]*

12. If any monitoring well becomes damaged or inoperable, the permittee shall notify the Department 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 prior to installation. *[62-520.600][62-620.320(6)]*.

13. All piezometers and monitoring wells not part of the approved ground water monitoring plan are to be plugged and abandoned in accordance with Rule 62-532.500(4), F.A.C., unless future use is intended. *[62-532.500(4)]*.

14. 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. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department in a written report within 7 days of the sinkhole discovery.

15. Ground water monitoring test results shall be submitted on Part D of DEP Form 62-620.910(10) (attached) and shall be submitted to the address specified in I.E.3. Results shall be submitted with the DMR for each month listed in the following schedule.

SAMPLE PERIOD	REPORT DUE DATE
January - March	April 28
April - June	July 28
July - September	October 28
October - December	January 28

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

Section IV is not applicable to this facility.

V. OPERATION AND MAINTENANCE REQUIREMENTS

A. General 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, inclnding 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 the 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; and

   g. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules.

   [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 that have been taken out of service.

B. Storm Water Requirements

1. The permittee shall amend the SWPPP whenever there is a change at the facility or change in the operation of the facility that materially increases the potential for the ancillary activities to result in a discharge of additional, significant amounts of pollutants. The permittee shall have 30 days after facility or operational changes to update the SWPPP as necessary.

C. Impoundment Design, Construction, Operation, and Maintenance

1. All impoundments used to hold or treat wastewater and other associated wastes shall be operated and maintained to prevent the discharge of pollutants to waters of the State, except as authorized under this permit.

2. Construction, operation, and maintenance of any impoundment shall be in accordance with all relevant Local, Regional, State and Federal regulations and shall be certified by a qualified, Florida registered professional engineer and permitted and inspected by the appropriate agency prior to use.

VI. SCHEDULES

1. The following improvement actions shall be completed according to the following schedule. The Stormwater Pollution Prevention (SWPP) Plan shall be prepared and implemented in accordance with Part VII of this permit.

Improvement Action	Completion Date
1. Develop SWPP Plan	Effective date of permit plus 6 months
2. Implement SWPP Plan	Effective date of permit plus 18 months

2. If the permittee wishes to continue operation of this wastewater facility after the expiration date of this permit, the permittee shall submit an application for renewal no later than one-hundred and eighty days (180) prior to the expiration date of this permit. Application shall be made using the appropriate forms listed in Rule 62-620.910, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C. *[62-620.335(1) and (2)*

3. The permittee shall submit a copy of the Manatee Protection Plan, including any amendments, with the permit renewal application to each of the following agencies no later than one-hundred and eighty days (180) prior to the expiration date of this permit:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Florida Fish and Wildlife Conservation Commission
Bureau of Protected Species Management
620 South Meridian Street
OES-BPS
Tallahassee, Florida 32399-1600

And

US Fish and Wildlife Service
Jacksonville Field Office
7915 Baymeadows Way, Suite 200
Jacksonville, Florida 32256-7517

4. The permittee shall submit the information required by the applicable provisions of 40 CFR 122.21(r) in accordance with the following:

   a. Within six months of the effective date of this permit, the permittee shall submit to the Department a Plan of Study (POS) to address the timely implementation of the 316(b) cooling water intake regulations. The POS shall include a schedule for the submittal of all applicable §122.21(r) forms, any associated reports, and peer review documentation. All applicable forms, reports, and associated material shall be submitted as soon as practicable but no later than 180 days prior to the expiration date of the permit (also the due date for submission of the permit renewal application)

PERMITTEE: Florida Power & Light
FACILITY: Ft. Myers Power Plant

PERMIT NUMBER: FL0001490 (Major)
EXPIRATION DATE: January 19, 2021

VII. BEST MANAGEMENT PRACTICES/STORMWATER POLLUTION PREVENTION PLANS

1. 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 a Stormwater Pollution Prevention Plan (SWPPP) for the facility covered by this permit. The SWPPP shall be 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. The plan shall identify potential sources of pollution that may reasonably be expected to affect the quality of stormwater discharges associated with industrial activity from the facility. In addition, the plan shall describe and ensure the implementation of practices which are to be used to reduce the pollutants, including mercury, in stormwater discharges associated with industrial activity at the facility and to assure compliance with the terms and conditions of this permit. Facilities must implement the provisions of the SWPPP required under this part as a condition of this permit. The plan shall include, at a minimum, the following items:

   a. Specific individual(s) within the facility organization as members of a SWPPP Team that are responsible for developing the SWPPP 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 SWPPP.

   b. A description of potential sources which may reasonably be expected to add significant amounts of pollutants to stormwater discharges or which may result in the discharge of pollutants during dry weather from separate storm sewers draining the facility. The plan shall identify all activities and significant materials that may potentially be significant 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 significant materials are exposed to precipitation, locations where major spills or leaks identified under Item (2)(c) (spills and leaks) 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 significant amounts of pollutants, a prediction of the direction of flow, and an identification of the types of pollutants which are likely to be present in stormwater discharges associated with industrial activity. Factors to consider include the toxicity of chemical; quantity of chemicals used, produced or discharged; the likelihood of contact with stormwater; and history of significant leaks or spills of toxic or hazardous pollutants. Flows with a significant 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 significant 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 significant spills and significant 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 list shall be updated as appropriate during the term of the 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; significant dust or particulate generating processes; loading/unloading areas; and on-site waste disposal practices. The description shall specifically list any significant 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.

c. A description of stormwater management controls appropriate for the facility and implement such controls. The appropriateness and priorities of controls in a 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 SWPPP. 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 (4) 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 SWPPP or otherwise responsible for stormwater management at all levels of responsibility of the components and goals of the SWPPP. Training should address topics such as spill response, good housekeeping and material management practices. A pollution prevention plan shall identify periodic dates for such training.
   (6) A description of incidents (such as spills, or other discharges), along with other information describing the quality and quantity of stormwater discharges shall be included in the plan required under this part. Inspections and maintenance activities shall be documented and records of such activities shall be incorporated into the plan.
   (7) Non-Stormwater Discharges
      (a) The plan shall include a certification that each "stormwater-only" discharge authorized under this permit has been tested or evaluated for the presence of non-stormwater discharges. (This section is not applicable to those discharges authorized under this permit that have been identified in the application as having non-stormwater components.) The certification shall include the identification of potential significant 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. Certifications shall be signed in accordance with paragraph (6) of this section. 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 stormwater pollution plan shall indicate why the certification required by this part was not feasible, along with the identification of potential significant 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 (iii) below.
      (b) Except for flows from firefighting 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 of Florida 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 significant 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.

d. A Comprehensive Site Compliance Evaluation. Qualified personnel shall conduct site compliance evalnations at appropriate intervals specified in the plan, but, except as provided in paragraph (4)(d) of this section, 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 the 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 (2) of this section (description of potential pollutant sources) and pollution prevention measures and controls identified in the plan in accordance with paragraph (3) of this section (measures and controls) 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, major observations relating to the implementation of the SWPPP, and actions taken in accordance with paragraph (4)(b) of this section shall be made and retained as part of the SWPPP for at least one year after coverage under this permit terminates. The report shall identify any incidents of non-compliance. 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 SWPPP and this permit. The report shall be signed in accordance with paragraph (6) (signatory requirements) of this section.

e. Consistency with other plans. SWPPP 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 Best Management Practices (BMP) Programs otherwise required by an NPDES permit for the facility as long as such requirement is incorporated into the SWPPP.

f. Signatory Authority and Management Responsibilities. The SWPPP shall be signed in accordance with Rule 62-620.305, Florida Administrative Code, and shall be reviewed by the facility engineer and facility manager. A copy of the plan shall be retained at the facility and shall be made available to the Department upon request, or in the case of a stormwater discharge associated with industrial activity that discharges through a municipal separate storm sewer system, to the operator of the municipal system.

g. Plan Review. 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 the 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 this Part. Within 30 days of such notification from the Department, the permittee

shall make the required changes to the plan and shall submit to the Department a written certification that the requested changes have been made.

h. Keeping Plans Current. The permittee shall amend the plan whenever there is a change in design, construction, operation, or maintenance of the facility which has a significant effect on the potential for the discharge of pollutants to surface waters of the State of Florida; if the SWPPP proves to be ineffective in eliminating or significantly minimizing pollutants from sources identified under paragraph (2) (description of potential pollutant sources) of this section; or, in otherwise achieving the general objectives of controlling pollutants in stormwater discharges associated with industrial activity. Amendments to the plan may be reviewed by the Department in the same manner as described in paragraphs (6) and (7) of this section.

[62-620.100(3)(m)]

VIII. OTHER SPECIFIC CONDITIONS

A. Specific Conditions Applicable to All Permits

1. Where required by Chapter 471 or Chapter 492, F.S., applicable portions of reports that must be submitted under this permit shall be signed and sealed by a professional engineer or a 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 South District Office, are made a part hereof.

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.

4. The permittee shall provide verbal notice to the Department's South District Office as soon as practical after discovery of a sinkhole or other karst feature within an area for the management or application of wastewater, or wastewater sludges. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department's South District Office in a written report within 7 days of the sinkhole discovery. *[62-620.320(6)]*

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 discharge to waters of the State 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 (**July 23, 2020**) using the appropriate forms listed in Rule 62-620.910, F.A.C., and in the manner established in the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.; or

b. the permittee has made complete the application for renewal of this permit before the permit expiration date.

[62-620.335(1)-(4), F.A.C.]

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 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, EPA established Total Maximum Daily Loads (TMDLs), or other information show a need for a different limitation, monitoring requirement, or more stringent requirements or any applicable standards pertaining to the operation and maintenance of coal combustion waste impoundments.

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 permit shall be reopened for revision as appropriate to address new information that was not available at the time of this permit issuance or to comply with requirements of new regulations, standards, or judicial decisions relating to CWA 316(b).

IX. GENERAL CONDITIONS

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1)]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2)]*

3. As provided in Subsection 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 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)]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7)]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8)]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;

   b. Have access to and copy any records that shall be kept under the conditions of this permit;

   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and

   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.*[62-620.610(9)]*

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, F.S., or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10)]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that

were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11)]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12)]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13)]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. *[62-620.610(14)]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility or activity and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15)]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rules 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 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)]*

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 heing 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 Discharge Monitoring Report (DMR), DEP Form 62-620.910(10), or as specified elsewhere in the permit.

    b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

    d. Except as specifically provided in Rule 62-160.300, F.A.C., any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health Environmental Laboratory Certification Program (DOH ELCP). Such certification shall be for the matrix, test method and analyte(s) being measured to comply with this permit. For domestic wastewater facilities, testing for parameters listed in Rule 62-160.300(4), F.A.C., shall be conducted under the direction of a certified operator.

    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 South District Office any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

a. The following shall be included as information which must be reported within 24 hours under this condition:

(1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
(2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
(3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
(4) Any unauthorized discharge to surface or ground waters.

b. Oral reports as required by this subsection shall be provided as follows:

(1) For unauthorized releases or spills of treated or untreated 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 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 the Department's South 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 South District Office shall waive the written report.

[62-620.610(20)]

21. The permittee shall report all instances of noncompliance not reported under Permit Conditions IX.17, 18 or 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Permit Condition IX.20 of this permit. *[62-620.610(21)]*

22. Bypass Provisions.

    a. "Bypass" means the intentional diversion of waste streams from any portion of a treatment works.

    b. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
       (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
       (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
       (3) The permittee submitted notices as required under Permit Condition IX.22.b. 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.5. of this permit; and
       (4) The permittee complied with any remedial measures required under Permit Condition IX. 5. 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)]*

PERMITTEE: Florida Power & Light
FACILITY: Ft. Myers Power Plant

PERMIT NUMBER: FL0001490 (Major)
EXPIRATION DATE: January 19, 2021

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

Elsa A. Potts, P.E.
Program Administrator
Industrial Wastewater Program
Division of Water Resource Management

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 (FPL)
MAILING ADDRESS: PO Box 14000
Juno Beach, Florida 33408-420

FACILITY: Ft. Myers Power Plant
LOCATION: 10650 Palm Beach Blvd
Fort Myers, FL 33905-5903

COUNTY: Lee
OFFICE: South District

PERMIT NUMBER: FL0001490-008-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-010
MONITORING GROUP DESCRIPTION: Combined plant discharge
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Water (Intake) (Mode I and II)	Sample Measurement										
PARM Code 00011 7 Mon. Site No. INT-1	Permit Requirement						Report (Mo.Avg.)	Deg F		6/Day	Meter
Temp. Diff. between Intake and Discharge (Mode I*)	Sample Measurement										
PARM Code 61576 1 Mon. Site No. EFF-1	Permit Requirement						Report (Mo.Avg.)	Deg F		6/Day	Meter
Temp. Diff. between Intake and Discharge (Mode II*)	Sample Measurement										
PARM Code 61576 Q Mon. Site No. EFF-1	Permit Requirement						13.0 (Mo.Avg.)	Deg F		6/Day	Meter
Oxidants, Total Residual	Sample Measurement										
PARM Code 34044 1 Mon. Site No. EFF-1	Permit Requirement						0.01 (Day.Max.)	mg/L		Weekly	Grab
Oxidants, Total Residual	Sample Measurement										
PARM Code 34044 Q Mon. Site No. EFF-1	Permit Requirement						0.01 (Day.Max.)	mg/L		Monthly	Grab
pH	Sample Measurement										
PARM Code 00400 1 Mon. Site No. EFF-1	Permit Requirement				6.0 (Day.Min.)		8.5 (Day.Max.)	s.u.		Weekly	Meter
Chloride (as Cl)	Sample Measurement										
PARM Code 00940 7 Mon. Site No. INT-1	Permit Requirement						Report (Day.Max.)	mg/L		Monthly	Grab

*Mode I: January 1 until the first instance of Temperature >= 74 deg F and first instance of Temperature < 74 deg F until December 31; Otherwise Mode II applies.

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):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 30 of 48

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 (FPL)
MAILING ADDRESS: PO Box 14000
Juno Beach, Florida 33408-420

FACILITY: Ft. Myers Power Plant
LOCATION: 10650 Palm Beach Blvd
Fort Myers, FL 33905-5903

COUNTY: Lee
OFFICE: South District

PERMIT NUMBER: FL0001490-008-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-010
MONITORING GROUP DESCRIPTION: Combined plant discharge
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT FREQUENCY: Quarterly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total	Sample Measurement										
PARM Code 00600 1 Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 7 Mon. Site No. INT-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 1 Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 7 Mon. Site No. INT-1	Permit Requirement						Report (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):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 31 of 48

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 (FPL)
MAILING ADDRESS: PO Box 14000
Juno Beach, Florida 33408-420

FACILITY: Ft. Myers Power Plant
LOCATION: 10650 Palm Beach Blvd
Fort Myers, FL 33905-5903

COUNTY: Lee
OFFICE: South District

PERMIT NUMBER: FL0001490-008-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-010
MONITORING GROUP DESCRIPTION: Combined plant discharge
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING NOT REQUIRED: ☐
MONITORING PERIOD From: _____ To: _____

REPORT FREQUENCY: Toxicity
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
7-DAY CHRONIC STATRE Americamysis bahia(Routine)	Sample Measurement										
PARM Code TRP3E P Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		Semiannually	24-hr TPC
7-DAY CHRONIC STATRE Americamysis bahia(Additional)	Sample Measurement										
PARM Code TRP3E Q Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Americamysis bahia(Additional)	Sample Measurement										
PARM Code TRP3E R Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Menidia beryllina(Routine)	Sample Measurement										
PARM Code TRP6B P Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		Semiannually	24-hr TPC
7-DAY CHRONIC STATRE Menidia beryllina(Additional)	Sample Measurement										
PARM Code TRP6B Q Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Menidia beryllina(Additional)	Sample Measurement										
PARM Code TRP6B R Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit

*ENTER "MNR" IN THE RESULTS COLUMN FOR EACH TEST THAT IS NOT REQUIRED.

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):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 32 of 48

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 (FPL)
MAILING ADDRESS: PO Box 14000
Juno Beach, Florida 33408-420

FACILITY: Ft. Myers Power Plant
LOCATION: 10650 Palm Beach Blvd
Fort Myers, FL 33905-5903

COUNTY: Lee
OFFICE: South District

PERMIT NUMBER: FL0001490-008-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-111
MONITORING GROUP DESCRIPTION: OTCW discharge from Unit 1
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-1	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Daily; 24 hours	Flow Totalizer

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):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 33 of 48

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 (FPL)
MAILING ADDRESS: PO Box 14000
Juno Beach, Florida 33408-420

FACILITY: Ft. Myers Power Plant
LOCATION: 10650 Palm Beach Blvd
Fort Myers, FL 33905-5903

COUNTY: Lee
OFFICE: South District

PERMIT NUMBER: FL0001490-008-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-112
MONITORING GROUP DESCRIPTION: OTCW discharge from Unit 2
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-2	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Daily; 24 hours	Flow Totalizer

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):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 34 of 48

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 (FPL)
MAILING ADDRESS: PO Box 14000
Juno Beach, Florida 33408-420

FACILITY: Ft. Myers Power Plant
LOCATION: 10650 Palm Beach Blvd
Fort Myers, FL 33905-5903

COUNTY: Lee
OFFICE: South District

PERMIT NUMBER: FL0001490-008-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-130
MONITORING GROUP DESCRIPTION: RO reject
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
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-3	Permit Requirement		Report (Day.Max.)	MGD						Semi-Annually; twice per year	Calculated
Oil and Grease	Sample Measurement										
PARM Code 00556 P Mon. Site No. OUI-1	Permit Requirement					15.0 (Mo.Avg.)	30.0 (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 P Mon. Site No. OUI-1	Permit Requirement					30.0 (Mo.Avg.)	100.0 (Day.Max.)	mg/L		Semi-Annually; twice per year	Grab

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 35 of 48

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 (FPL)
MAILING ADDRESS: PO Box 14000
Juno Beach, Florida 33408-420

FACILITY: Ft. Myers Power Plant
LOCATION: 10650 Palm Beach Blvd
Fort Myers, FL 33905-5903

COUNTY: Lee
OFFICE: South District

PERMIT NUMBER: FL0001490-008-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-170
MONITORING GROUP DESCRIPTION: Cooling tower discharge
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-4	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Daily; 24 hours	Flow Totalizer
Chlorine, Total Residual (Dsg. Time)	Sample Measurement										
PARM Code 00208 P Mon. Site No. OTH-1	Permit Requirement		120 (Day.Max.)	min/day						Daily; 24 hours	Calculated
Oxidants, Total Residual	Sample Measurement										
PARM Code 34044 P Mon. Site No. OUI-2	Permit Requirement						0.20 (Day.Max.)	mg/L		Weekly	Grab

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Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 36 of 48

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 (FPL)
MAILING ADDRESS: PO Box 14000
Juno Beach, Florida 33408-420

FACILITY: Ft. Myers Power Plant
LOCATION: 10650 Palm Beach Blvd
Fort Myers, FL 33905-5903

COUNTY: Lee
OFFICE: South District

PERMIT NUMBER: FL0001490-008-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-180
MONITORING GROUP DESCRIPTION: Auxiliary Equipment Cooling Water from Units 1 and 2
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-5	Permit Requirement		Report (Day.Max.)	MGD						Weekly	Calculated
TRO-Discharge Time	Sample Measurement										
PARM Code 04223 1 Mon. Site No. OTH-2	Permit Requirement						120 (Daily Max.)	min/day		Daily; 24 hours	Calculated

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Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 37 of 48

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 (FPL)
MAILING ADDRESS: PO Box 14000
Juno Beach, Florida 33408-420

FACILITY: Ft. Myers Power Plant
LOCATION: 10650 Palm Beach Blvd
Fort Myers, FL 33905-5903

COUNTY: Lee
OFFICE: South District

PERMIT NUMBER: FL0001490-008-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-020
MONITORING GROUP DESCRIPTION: Evaporation/Percolation Pond Emergency Overflow
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: _____ To: _____

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. EFF-2	Permit Requirement		Report (Day.Max.)	MGD						Weekly Upon Discharge	Estimated
Oil and Grease	Sample Measurement										
PARM Code 00556 P Mon. Site No. EFF-2	Permit Requirement					15.0 (Mo.Avg.)	30.0 (Day.Max.)	mg/L		Weekly Upon Discharge	Grab
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 P Mon. Site No. EFF-2	Permit Requirement					20.0 (Mo.Avg.)	100.0 (Day.Max.)	mg/L		Weekly Upon Discharge	Grab

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Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 38 of 48

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Ft. Myers Power Plant
Permit Number: FL0001490-008-IW1S
County: Lee
Office: South District

Monitoring Well ID: MWB-MW4
Well Type: Background
Description: Background well MW4
Re-submitted DMR: ☐

Report Frequency: Quarterly
Program: Industrial

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Nitrogen, Nitrate, Total (as N)	00620		Report	mg/L	Grab	Quarterly				
Specific Conductance	00095		Report	umhos/cm	Grab	Quarterly				
pH	00400		Report	s.u.	Grab	Quarterly				
Chloride (as Cl)	00940		Report	mg/L	Grab	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
Water Level Relative to NGVD	82545		Report	ft	Measured	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 39 of 48

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Ft. Myers Power Plant
Permit Number: FL0001490-008-IW1S
County: Lee
Office: South District

Monitoring Well ID: MWB-MW4
Well Type: Background
Description: Background well MW4
Re-submitted DMR: ☐

Report Frequency: Annually
Program: Industrial

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Carbon, Total Organic (TOC)	00680		Report	mg/L	Grab	Annually				
Petrol Hydrocarbons, Total Recoverable	45501		Report	mg/L	Grab	Annually				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 40 of 48

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Ft. Myers Power Plant
Permit Number: FL0001490-008-IW1S
County: Lee
Office: South District

Monitoring Well ID: MWC-OB1
Well Type: Compliance
Description: Compliance well OB1
Re-submitted DMR: ☐

Report Frequency: Quarterly
Program: Industrial

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Nitrogen, Nitrate, Total (as N)	00620		10.0	mg/L	Grab	Quarterly				
Specific Conductance	00095		60000.0	umhos/cm	Grab	Quarterly				
pH	00400		Report	s.u.	Grab	Quarterly				
Chloride (as Cl)	00940		Report	mg/L	Grab	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
Water Level Relative to NGVD	82545		Report	ft	Measured	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 41 of 48

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Ft. Myers Power Plant
Permit Number: FL0001490-008-IW1S
County: Lee
Office: South District

Monitoring Well ID: MWC-OB1
Well Type: Compliance
Description: Compliance well OB1
Re-submitted DMR: ☐

Report Frequency: Annually
Program: Industrial

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Carbon, Total Organic (TOC)	00680		Report	mg/L	Grab	Annually				
Petrol Hydrocarbons,Total Recoverable	45501		Report	mg/L	Grab	Annually				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 42 of 48

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Ft. Myers Power Plant
Permit Number: FL0001490-008-IW1S
County: Lee
Office: South District

Monitoring Well ID: MWC-OB4
Well Type: Compliance
Description: Compliance well OB4
Re-submitted DMR: ☐

Report Frequency: Quarterly
Program: Industrial

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Nitrogen, Nitrate, Total (as N)	00620		10.0	mg/L	Grab	Quarterly				
Specific Conductance	00095		60000.0	umhos/cm	Grab	Quarterly				
pH	00400		Report	s.u.	Grab	Quarterly				
Chloride (as Cl)	00940		Report	mg/L	Grab	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
Water Level Relative to NGVD	82545		Report	ft	Measured	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 43 of 48

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Ft. Myers Power Plant
Permit Number: FL0001490-008-IW1S
County: Lee
Office: South District

Monitoring Well ID: MWC-OB4
Well Type: Compliance
Description: Compliance well OB4
Re-submitted DMR: ☐

Report Frequency: Annually
Program: Industrial

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Carbon, Total Organic (TOC)	00680		Report	mg/L	Grab	Annually				
Petrol Hydrocarbons,Total Recoverable	45501		Report	mg/L	Grab	Annually				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 44 of 48

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Ft. Myers Power Plant
Permit Number: FL0001490-008-IW1S
County: Lee
Office: South District

Monitoring Well ID: MWI-OB2
Well Type: Intermediate
Description: Intermediate well OB2
Re-submitted DMR: ☐

Report Frequency: Quarterly
Program: Industrial

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Nitrogen, Nitrate, Total (as N)	00620		Report	mg/L	Grab	Quarterly				
Specific Conductance	00095		Report	umhos/cm	Grab	Quarterly				
pH	00400		Report	s.u.	Grab	Quarterly				
Chloride (as Cl)	00940		Report	mg/L	Grab	Quarterly				
Solids, Total Dissolved (TDS)	70295		Report	mg/L	Grab	Quarterly				
Water Level Relative to NGVD	82545		Report	ft	Measured	Quarterly				
Sulfate, Total	00945		Report	mg/L	Grab	Quarterly				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 45 of 48

GROUNDWATER MONITORING REPORT - PART D

Facility Name: FPL - Ft. Myers Power Plant
Permit Number: FL0001490-008-IW1S
County: Lee
Office: South District

Monitoring Well ID: MWI-OB2
Well Type: Intermediate
Description: Intermediate well OB2
Re-submitted DMR: ☐

Report Frequency: Annually
Program: Industrial

Monitoring Period From: _____ To: _____

Date Sample Obtained: _____

Time Sample Obtained: _____

Was the well purged before sampling? ___Yes ___ No

Parameter	PARM Code	Sample Measurement	Permit Requirement	Units	Sample Type	Frequency of Analysis	Detection Limits	Analysis Method	Sampling Equipment Used	Samples Filtered (L/F/N)
Carbon, Total Organic (TOC)	00680		Report	mg/L	Grab	Annually				
Petrol Hydrocarbons,Total Recoverable	45501		Report	mg/L	Grab	Annually				

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COMMENTS AND EXPLANATION (Reference all attachments here):

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 46 of 48

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. 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:

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.
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.

Docket No. 20180007-EI
FDEP NPDES Permit for PFM
Exhibit MWS-3, Page 47 of 48

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.
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.

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Exhibit MWS-3, Page 48 of 48

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 5
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Michael W. Sole MWS-4



Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the matter of:
Approval of FPL Fort Myers Plant
Manatee Protection Plan

DEP Permit No. FL0001490
Lee County

Mr Ron Hix
Florida Power & Light Company
P.O. Box 088801
North Palm Beach, FL 33408-08801

NOTICE OF AGENCY ACTION

The Department of Environmental Protection hereby gives notice of its approval of the enclosed Manatee Protection Plan for the FPL Fort Myers Plant, completed July 12, 1999 pursuant to Specific Condition 14 of Permit Number FL0001490 and noticed pursuant to the Final Settlement Agreement, dated March 1998, between Southwest Florida Marine Trades Association, Inc. and Florida Power and Light Company and the Department.

A person whose substantial interests are affected by the Department action may petition for an administrative hearing in accordance with sections 120.569 and 120 57 of the Florida Statutes.

The petition must contain the information set forth below and must be filed (received) in the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within twenty-one days of receipt of this notice of intent. Petitions filed by any other person must be filed within twenty-one days of publication of the public notice or within twenty-one days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person 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 of the Florida Statutes, or to intervene in this proceeding and participate as a party to it Any subsequent intervention will be only at the discretion of the presiding officer upon the filing of a motion in compliance with rule 28-5 207 of the Florida Administrative Code.

A petition must contain the following information:
(a) The name, address, and telephone number of each petitioner; the Department case identification number and the county in which the subject matter or activity is located;
(b) A statement of how and when each petitioner received notice of the Department action;

(c) A statement of how each petitioner's substantial interests are affected by the Department action;
(d) A statement of the material facts disputed by the petitioner, if any;
(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department action;
(f) A statement of which rules or statutes the petitioner contends require reversal or modification of the Department action; and
(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department final action may be different from the position taken by it in this order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation under section 120.573 of the Florida Statutes is not available for this proceeding.

This action is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above. Upon the timely filing of a petition this order will not be effective until further order of the Department.

Any party to the order has the right to seek judicial review of the order 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 30 days from the date when the final order 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) 487-1855

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF AGENCY ACTION and all copies were mailed before the close of business on 08-18-99 to the listed persons.

FILING AND ACKNOWLEDGMENT

FILED, on this date, under section 120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

S. Shields 08-18-99

(Clerk) (Date)

Copies furnished to:

Abdul Ahmadi, DEP South District
Kipp Frohlich, FWC Tallahassee
Jennifer Fitzwater, DEP Office of General Counsel
Ken Stead, Southwest Florida Marine Trades Association, Inc.
Chairman, Board of Lee County Commissioners
Jim Valade, U.S. Fish and Wildlife Service
Save the Manatee Club

Florida Fish and Wildlife Conservation Commission

James L. "Jamie" Adams, Jr., Bushnell
Barbara C. Barsh, Jacksonville
Patrick E. Geraghty, Ft. Myers
Quinton L. Hedgepeth, DDS, Miami
H.A. "Herky" Huffman, Deltona
Thomas B. Kilber, Lakeland
David K. Meehan, St. Petersburg
Julie K. Morris, Sarasota
Tony Moss, Miami
Edwin P. Roberts, DC, Pensacola
John D. Rood, Jacksonville

ALLAN L. EGBERT, Ph.D., Executive Director
VICTOR J. HELLER, Assistant Executive Director

620 South Meridian Street
Tallahassee, FL 32399-1600
www.state.fl.us/gfc
(850)487-3796
IDD (850)488-9542

July 13, 1999

Vince Seibold
Florida Department of Environmental Protection
Industrial Wastewater Section
Mail Station 3545
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RECEIVED
JUL 19 1999
Industrial Wastewater Section

Dear Vince;

I have attached the Manatee Protection Plan dated July 12, 1999 for Florida Power & Light's (FPL) Ft. Myers facility. The Bureau of Protected Species Management has reviewed the attached plan and with this letter acknowledges our acceptance of this plan as that required by permit condition 14, of the FPL-Ft. Myers NPDES permit. I have provided the following chronological list recounting the submittal of Florida Power & Light-Ft. Myers draft Manatee Protection Plans and our corresponding responses.

October 12, 1998	The Bureau of Protected Species Management receives a draft Manatee Protection Plan from Florida Power & Light's Ft. Myers facility
December 7, 1998	The Bureau of Protected Species Management provides verbal comments and recommended modifications to FPL regarding their Ft. Myers facility's draft Manatee Protection Plan.
December 8, 1998	FPL provides the Bureau of Protected Species Management with an interim Manatee Protection Plan for the Ft. Myers facility while a final plan is completed.
December 10, 1998	The Bureau of Protected Species Management notifies the DEP's Industrial Wastewater Section that it does not object to the interim plan
March 10, 1999	The Bureau of Protected Species Management receives the FPL-Ft. Myers draft Manatee Protection Plan and additional information on the current manatee protection wells.

May 7, 1999	The Bureau of Protected Species Management provides comments and recommended modifications to the FPL-Ft. Myers Manatee Protection Plan.
May 12, 1999	The Bureau of Protected Species Management provides a second set of additional recommendations and wording changes for consistency to FPL-Ft. Myers
May 28, 1999	The Bureau of Protected Species Management provides the U. S. Fish and Wildlife Service (USFWS) with a copy of the final draft of the FPL-Ft. Myers Manatee Protection Plan for review and comment.
June 1, 1999	The USFWS provides several recommended modifications to the FPL-Ft. Myers final draft plan.
June 3, 1999	The Bureau of Protected Species receives a carbon copy of the USFWS letter to the Department's Industrial Wastewater Section providing their concurrence to the attached Manatee Protection Plan for the FPL-Ft. Myers facility.
July 12, 1999	The Bureau of Protected Species Management receives concurrence from FPL-Ft. Myers on the attached Manatee Protection Plan dated July 12, 1999.

If you have any questions or need further information, please call me at suncom 292-4330.

Sincerely,

OFFICE OF ENVIRONMENTAL SERVICES

R. Kipp Frohlich
Biological Administrator
Bureau of Protected Species Management

\rrm
NPDES.099\IWW-FPL-FtMyers-ltr.713.doc
ENV 7-2
Attachment

cc: R. Hix
J. Valade

United States Department of the Interior

FISH AND WILDLIFE SERVICE
6620 Southpoint Drive South
Suite 310
Jacksonville, Florida 32216-0912

JUN 01 1999

RECEIVED
JUN 3 1999
BUREAU OF PROTECTED SPECIES
MARINE RESOURCES DIVISION

Vince Seibold
Florida Department of Environmental Protection
Division of Water Facilities
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Seibold:

The Fish and Wildlife Service (Service) has reviewed manatee protection plans for the following facilities:

✓ Florida Power and Light's Fort Myers Plant
(State Industrial Wastewater Permit Number FL0001490)

Florida Power and Light's Ft. Lauderdale Plant
(State Industrial Wastewater Permit Number FL0001503)

Florida Power and Light's Port Everglades Plant
(State Industrial Wastewater Permit Number FL0001538)

The measures incorporated in these plans are consistent with the intent of the Florida Manatee Recovery Plan, which seeks to maintain safe and reliable warm water refuges for wintering manatees. The Service believes that the measures included in these plans will give manatees adequate protection during the periods specified in the permits at the respective power plants.

Thank you for the opportunity to review these plans.

Sincerely,

James A. Valade
Assistant Recovery Manatee Coordinator

cc: FDEP/BPSM - Ron Mezich
FWS Vero Beach Field Office - Jay Slack

Florida Power & Light – Fort Myers
Manatee Protection Plan

Purpose:

The purpose of the Ft. Myers Plant Manatee Protection Plan is to set forth Florida Power & Light Company's (FPL) procedures to comply with Specific Condition 14 of the facility's State Industrial Wastewater Permit Number FL0001490 that was issued on April 10, 1998. This Specific Condition reads, in part:

14. The permittee, in so far as required to comply with Tasks 25 and 251 of the U.S. Fish and Wildlife Service (USFWS) "Florida Manatee Recovery Plan," shall develop a plan and procedures addressing potential manatee impacts ... All plans, if required, shall include an implementation schedule and address, at a minimum:

    (a) Plans to minimize disruption to warm-water outflows during the winter and response procedures in case of disruptions.

    (b) Strategy to maintain discharge temperatures that will sustain manatees during cold events.

    (c) Plan to monitor ambient and discharge water temperatures

    (d) Precautions to minimize hazards to manatees at intake and outfall areas.

    (e) Timely communication to manatee recovery program personnel of any long term changes in the availability of warm water.

Compliance with Specific Condition 14:

1. This Manatee Protection Plan will be in effect during the term of the permit. In order for the plant's warm water discharge to provide a safe, warm water refuge for the manatees and to comply with Specific Condition 14, FPL will take the following actions:

    a) In the case of an unplanned shutdown or plant failure that will affect the warm water refuge from November 15 through March 31, when the ambient water temperature is below 61°F, the Florida Wildlife Conservation Commission (FWCC) and USFWS will be notified no later than four (4) hours after the event has occurred. The following agency representatives shall be notified in the above referenced event or if any distressed manatees are observed at any time:

    FWCC – Florida Marine Research Institute – Marine Mammal Pathobiology Lab: (813) 893-2904
    USFWS – Jacksonville Field Office: (904) 232-2580

    The FWCC, Bureau of Protected Species Management (BPSM) shall be provided a schedule of any anticipated in-water work within the discharge canal or work that will affect the warm water refuge during the period of November 15 through March 31 each year. This would include schedules for work being done in conjunction with the repowering of the Ft. Myers plant. Schedules for work pursuant to the repowering project should be updated and provided to BPSM as schedule changes occur. No routine in-water maintenance work shall occur in the discharge canal from November 15 through March 31, unless it is considered essential by FPL and approved by BPSM prior to the start of work. If emergency in-water work is needed, the BPSM will be notified and consulted no later than two weeks following the commencement of the activity. All vessels used in the operation or associated with the activity shall be operated pursuant to the attached standard manatee construction conditions.

b) From November 15 through March 31 each year, to coincide with the time of greatest manatee abundance, if the ambient water temperature falls below 61°F, the FPL Ft. Myers power plant shall endeavor to operate in a manner that maintains the water temperature in an adequate portion of the discharge canal at or above 68°F, until such time as the ambient water temperature reaches 61°F, unless otherwise authorized by the BPSM and the USFWS, or unless safety or reliability of the plant would be compromised.

c) The FPL Ft. Myers power plant will provide personnel from the BPSM, USFWS, Florida Marine Research Institute, USGS-Sirenia Project, or a designee of these agencies, access to FPL Ft. Myers power plant property to conduct manatee research and monitoring activities which may include, placing, maintaining and downloading data from temperature data loggers (These temperature data loggers will be used to collect air and water temperature data in an ongoing research effort to better understand manatee behavior patterns in response to artificial warm water refugia and environmental variables. The temperature data loggers will be placed in the discharge canal and at ambient water and air locations) Access would be limited to normal business hours (8:00 a.m. to 5:00 p.m.) unless arrangements are made in advance with the FPL Fort Myers power plant.

Intake Area: No special surveys will be required for the intake canal.

Discharge Area: No special surveys will be required for the discharge canal.

d) Should the FPL decide to retire this plant, notice will be provided to FWCC and USFWS as soon as practical after a definite decision is made or, if possible, at least five years prior to the date of retirement

e) To assist in documenting long-term use patterns of this facility, FPL should conduct periodic aerial surveys of manatees at the Fort Myers facility. The continuation of the ongoing statewide aerial survey that FPL has funded in the past years meets these criteria.

g) The FPL Ft. Myers Power Plant will provide phone numbers for weekday and weekend notification of appropriate plant personnel for the purpose of allowing FWCC or USFWS to coordinate manatee rescue operations as necessary.

2. FPL actions, pursuant to this plan, that will be conducted for the current Ft. Myers Power Plant and the Ft Myers Power Plant post-repowering:

a) Provide a site map of the facility as a part of the plan that includes the following information;

1. The location of the intake pipes and outfall pipes.
2. Proximate streams, rivers, bays, etc.
3. The location of the condenser inlet and outlet temperature monitoring stations.
4. The location of any fuel barge docking facilities in relation to the discharge canal
5. The delineation of the no-entry boundary at the discharge canal.

b) In order to evaluate and determine what portions of the thermal discharge will provide a sufficient warm water refuge for manatees under potential cold stress water conditions; the FPL Ft Myers power plant will, within two (2) years of the effective date of this plan, provide a profile of the thermal gradient (either actual or calculated) of the discharge canal waters, as well as its gross bathymetry, at the mean rate of discharge when the ambient water temperature reaches a seasonal low

FLORIDA POWER & LIGHT – FT. MYERS PLANT
MANATEE PROTECTION PLAN

1a) STANDARD MANATEE CONSTRUCTION CONDITIONS FOR ARTIFICIAL WARM WATER REFUGIA DURING THE PERIOD OF NOVEMBER 15 THROUGH MARCH 31

The permittee shall comply with the following manatee protection conditions:

a. The permittee shall instruct all personnel associated with in-water work within the discharge canal and/or the warm water refuge of the potential presence of manatees and the need to avoid collisions with manatees. All vessels used in the operation or in association with the in-water work shall have an observer on board responsible for identifying the presence and location of manatee(s).

b. The permittee shall advise all construction personnel that there are civil and criminal penalties for harming, harassing, or killing manatees which are protected under the Marine Mammal Protection Act of 1972, The Endangered Species Act of 1973, and the Florida Manatee Sanctuary Act.

c. All vessels associated with in-water work associated with the discharge canal and/or warm water refuge shall operate at "no wake/idle" speeds at all times while in the manatee warm water refuge area. All vessels will follow routes of deep water whenever possible.

d. If manatee(s) are seen within the discharge canal and/or warm water refuge area all appropriate precautions shall be implemented to ensure protection of the manatee(s). These precautions shall include the immediate shutdown of equipment if necessary. Activities will not resume until the manatee(s) has departed to a safe distance on its own volition.

e. Any collision with and/or injury to a manatee shall be reported immediately to the Florida Fish & Wildlife Conservation Commission at (1-800-342-5367). Collision and/or injury should also be reported to the U.S. Fish and Wildlife Service in Jacksonville (1-904-232-2580).

Georgia Department of Natural Resources

2 Martin Luther King, Jr. Drive, S.E., Suite 1152 East Tower, Atlanta, Georgia 30334-9000
Noel Holcomb, Commissioner
Carol A. Couch, Ph.D., Director
Environmental Protection Division
404/656-4713

November 29, 2006



Mr. Charles H. Huling, P.E.
Vice President, Environmental Affairs
Georgia Power Company
Bin No. 10221
241 Ralph McGill Blvd.
Atlanta, Georgia 30308-3374

RE: Georgia Power Co. - Plant Scherer
NPDES Permit No. GA0035564

Dear Mr. Huling:

EPD has initiated a basin wide permitting strategy whereby permits are reissued within groups of river basins during specific years. As a part of that process, permits are extended until such time they can be reissued within that basin grouping.

The Environmental Protection Division (EPD) has received your application for reissuance of the referenced permit. EPD is hereby extending your permit until such time that it can be reissued within the appropriate river basin group.

Sincerely,

Carol A. Couch, Ph.D.
Director

CAC/ TEH
cc :Environmental Protection Agency

cc: Lisa Peacock, EPD Information Management Unit

cc: Gigi Steele, EPD Municipal Permitting Unit

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 6
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Michael W. Sole MWS-5

Georgia Department of Natural Resources
205 Jesse Hill Jr., S.E., Suite 1152 East Floyd Tower, Atlanta, Georgia 30334
Lonice C. Barrett, Commissioner
Harold F. Reheis, Director
David Word, Assistant Director
Environmental Protection Division
404/656-4713

January 30, 2002

Mr. C. M. Hobson
Vice President, Environmental Affairs
Georgia Power Company
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308

RE: Plant Scherer
NPDES Permit No. GA0035564

Dear Mr. Hobson:

Pursuant to the Georgia Water Quality Control Act, as amended; the Federal Clean Water Act, as amended; and the Rules and Regulations promulgated thereunder, we have issued the attached National Pollutant Discharge Elimination System (NPDES) permit for the specified wastewater treatment facility.

Please be advised that on and after the effective date indicated in the attached NPDES permit, the permittee must comply with all the terms, conditions and limitations of this permit.

Sincerely,

Harold F. Reheis
Director

HFR:th

Attachment

cc: Mr. Scott Gordon (w/attachment)
U. S. Environmental Protection Agency

WRE

PERMIT NO. GA0035564

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

AUTHORIZATION TO DISCHARGE UNDER THE
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Georgia Water Quality Control Act (Georgia Laws 1964, p. 416, as amended), hereinafter called the "State Act;" the Federal Water Pollution Control Act, as amended (33 U.S. C. 1251 et seq.), hereinafter called the "Federal Act;" and the Rules and Regulations promulgated pursuant to each of these Acts,

Georgia Power Company
241 Ralph McGill Boulevard, N.E.
Atlanta, Georgia 30308

is authorized to discharge from a facility located at

Plant Scherer (SIC 4911)
10986 Highway 87
Juliette, Monroe County, Georgia 31046

to receiving waters

Berry Creek, Lake Juliette (Rum Creek) and the Ocmulgee River (Ocmulgee River Basin)

in accordance with effluent limitations, monitoring requirements and other conditions set forth in Parts I, II and III hereof.

This permit shall become effective on January 30, 2002.

This permit and the authorization to discharge shall expire at midnight, November 30, 2006.

Signed this 30th day of January, 2002.

Director,
Environmental Protection Division

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

1. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 01 - Final Plant Discharge: Combined discharge of outfalls 01A, 01B, 01C, 01D, and 01E to the Ocmulgee River.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based (mg/l)				
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.	Measurement Frequency	Sample Type	Sample Location
Flow-m^3Day(MGD)	-	-	-	-	-	-	-
Total Residual Chlorine (TRC)		-	-	-	1/Day*	Grab	Final Discharge

The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored once per month by a grab sample of the final discharge to the Ocmulgee River.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

* Monitoring of TRC is required only during continuous service water chlorination for controlling asiatic clams.

Docket No. 20180007-EI
Environmental Protection Division of the Georgia
Department of Natural Resources Permit NPDES
Permit Number GA0035564 for Plant Scherer
Exhibit MWS-5, Page 4 of 28

2. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 01A - Cooling Tower Blowdown for Units 1, 2, 3 and 4.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations Concentration Based (mg/l) Daily Max.	Avg.	Inst. Max.	Monitoring Requirements Measurement Frequency	Sample Type	Sample Location
Flow-m^3Day (MGD)	-	-	-	-	-	-
Free Available Chlorine (FAC)	-	0.2	0.5	1/Week	Multiple Grabs	Blowdown Line
Total Residual Chlorine (TRC)	-	-	-	1/Week	Multiple Grabs	Blowdown Line
TRC Time (minutes/day/unit)	120	-	-	1/Week	Multiple Grabs	Blowdown Line
Total Residual Chlorine (TRC)	-	-	-	1/Week	Multiple Grabs	Service Water
Total Chromium	0.2	-	-	1/Year	Grab	Blowdown Line
Total Zinc	1.0	-	-	1/Year	Grab	Blowdown Line

Multiple grab samples are to be collected on 15 minute intervals during periods of FAC and TRC discharges attributable to cooling tower/condenser chlorination. Intervals are to be once per day during FAC and TRC discharges attributable to continuous service water chlorination. Samples are to be taken before each individual cooling tower blowdown combines with waste streams from other sources.

All numerical discharge limitations and monitoring requirements apply to the individual cooling tower blowdown from each generating unit. The limitations of 0.2/0.5 mg/l of FAC apply to FAC discharge attributable to cooling tower/ condenser chlorination (i.e. effluent concentration of FAC above that due to continuous service water system chlorination). Time of discharge of TRC attributable to cooling tower/condenser chlorination is limited to 2 hours/day/ unit. Simultaneous discharge of TRC attributable to cooling tower/condenser chlorination is prohibited.

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3. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 01B - Ash Transport Bleedoff (includes 03E Wastewater Basins Units 1, 2, 3 and 4, Low Volume Waste).

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based (mg/l)				
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.	Measurement Frequency	Sample Type	Sample Location*
Flow-m^3Day (MGD)	-	-	-	-	-	-	-
Total Suspended Solids (TSS)	-	-	30	100	2/Month	Grab	Bleedoff
Oil and Grease (O & G)	-	-	15	20	2/Month	Grab	Bleedoff

* Samples are to be taken at the ash transport bleedoff line prior to combination with any other wastewater stream.

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4. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 01C and 01D - Units 3 and 4 Cooling Tower Overflows/Basin Drains.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations Units (Specify) (mg/l)				Monitoring Requirements		
	Avg.	Inst. Max.	Daily Avg.	Daily Max.	Measurement Frequency	Sample Type	Sample Location
Flow-m^3Day (MGD)	-	-	-	-	-	-	-
Total Suspended Solids (TSS)	-	-	30	100	2/Month	Grab	Overflow
Oil & Grease (O & G)	-	-	15	20	2/Month	Grab	Overflow
Free Available Chlorine (FAC)	0.2	0.5	-	-	1/Week	Multiple Grabs	Overflow
Total Residual Chlorine (TRC)	-	-	-	-	1/Week	Multiple Grabs	Overflow
TRC Time (minutes/day/unit)	-	-	-	120	1/Week	Multiple Grabs	Overflow
Total Chromium	-	-	-	0.2	1/Year	Grab	Overflow
Total Zinc	-	-	-	1.0	1/Year	Grab	Overflow

TSS and O & G are required for basin drain discharges. FAC, TRC, TRC Time, chromium, and zinc are required for cooling tower overflow discharges.

Multiple grab samples are to be collected on 15 minute intervals during periods of FAC and TRC discharges attributable to cooling tower/condenser chlorination. Intervals are to be once per day during FAC and TRC discharges attributable to continuous service water chlorination. Samples are to be taken before each individual cooling tower overflow combines with waste streams from other sources.

All numerical discharge limitations and monitoring requirements apply to the individual cooling tower overflow from each generating unit. The limitations of 0.2/0.5 mg/l of FAC apply to FAC discharge attributable to cooling tower/condenser chlorination (i.e. effluent concentration of FAC above that due to continuous service water system chlorination). Time of discharge of TRC attributable to cooling tower/condenser chlorination is limited to 2 hours/day/unit. Simultaneous discharge of TRC attributable to cooling tower/condenser chlorination is prohibited.

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5. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 02 - Detention Pond (I Pond) and 02A - I Pond Bottom Drain; Discharges to Berry Creek (includes 02B, Fire Training Runoff and 02C, NPDES Basin Emergency Overflow).

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based (mg/l)				
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.	Measurement Frequency	Sample Type	Sample Location
Flow-m^3Day (MGD)	-	-	-	-	-	-	-
Total Residual Chlorine (TRC)[1]	-	-	-		1/Day	Grab	Final Discharge[3]

The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored once per month by a grab sample at the final discharge to Berry Creek or at the bottom drain when discharging.

There shall be no discharge of floating solids or visible foam in other than trace amounts.

(1) Monitoring of TRC is required only when continuous service water chlorination for controlling asiatic clams coincides with discharge from the NPDES Basin Emergency Overflow (02C) to I Pond.

(2) Monitoring for pH is required only when the NPDES Basin Emergency Overflow (02C) is discharging to I pond.

(3) Final discharge or bottom drain when discharging.

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6. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 04 - Service Water Final Discharge to Lake Juliette.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based				
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.	Measurement Frequency	Sample Type	Sample Location
Flow-m^3Day (MGD)	-	-	-	-	-	-	-
Temperature	-	-	-	-	1/Quarter	Grab	*
Total Residual Chlorine (TRC)		-	-	-	1/Quarter	Grab	*

There shall be no discharge of floating solids or visible foam in other than trace amounts.

* Temperature will be monitored and reported for the plant intake and the discharge. TRC will also be monitored and reported for the discharge. The temperature difference ("ΔT") between the intake and discharge temperature shall be calculated and entered on the monitoring report. The discharge temperature and TRC are the temperature and TRC recorded at a point not more than 50 feet from the discharge pipe outlet at a depth of 3 feet or other locations approved by the Division.

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7. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 05 and 06 - Units 1 and 2 Cooling Tower Overflows/Basin Drains to Lake Juliette.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations Units (Specify) (mg/l)				Monitoring Requirements		
	Avg.	Inst. Max.	Daily Avg.	Daily Max.	Measurement Frequency	Sample Type	Sample Location
Flow-m^3Day (MGD)	-	-	-	-	-	-	-
Total Suspended Solids (TSS)	-	-	30	100	2/Month	Grab	Overflow
Oil & Grease (O & G)	-	-	15	20	2/Month	Grab	Overflow
Free Available Chlorine (FAC)	0.2	0.5	-	-	1/Week	Multiple Grabs	Overflow
Total Residual Chlorine (TRC)	-	-	-	-	1/Week	Multiple Grabs	Overflow
TRC Time (minutes/day/unit)	-	-	-	120	1/Week	Multiple Grabs	Overflow
Total Chromium	-	-	-	0.2	1/Year	Grab	Overflow
Total Zinc	-	-	-	1.0	1/Year	Grab	Overflow

The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored twice per month by grab sampling. There shall be no discharge of floating solids or visible foam in other than trace amounts.

TSS, O & G and pH are required for basin drain discharges. FAC, TRC, TRC Time, chromium, zinc, and pH are required for cooling tower overflow discharges.

Multiple grab samples are to be collected on 15 minute intervals during periods of FAC and TRC discharges attributable to cooling tower/condenser chlorination. Intervals are to be once per day during FAC and TRC discharges attributable to continuous service water chlorination. Samples are to be taken before each individual cooling tower overflow combines with waste streams from other sources.

All numerical discharge limitations and monitoring requirements apply to the individual cooling tower overflow from each generating unit. The limitations of 0.2/0.5 mg/l of FAC apply to FAC discharge attributable to cooling tower/ condenser chlorination (i.e. effluent concentration of FAC above that due to continuous service water system chlorination). Time of discharge of TRC attributable to cooling tower/condenser chlorination is limited to 2 hours/day/unit. Simultaneous discharge of TRC attributable to cooling tower/condenser chlorination is prohibited.

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8. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 07 - Settling Pond Emergency Overflow to Lake Juliette (Ash Transport Water).

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based (mg/l)				
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.	Measurement Frequency*	Sample Type	Sample Location
Flow-m^3Day (MGD)	-	-	-	-	-	-	-
Total Suspended Solids (TSS)	-	-	30	100	2/Month	Grab	Overflow
Oil and Grease (O & G)	-	-	15	20	2/Month	Grab	Overflow

The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored twice per month by grab sampling.*

There shall be no discharge of floating solids or visible foam in other than trace amounts.

* Monitoring for TSS, O&G, and pH is required only when an overflow is occurring.

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9. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 08 - Employee Car Wash, 09 Service Water Pump Seal Water, 10 Service Water Screen Backwash, 12 Condensate/Filtered Water/Potable Water Tank Overflows discharging to Lake Juliette, and 11 River Intake Pump Seal Water discharging to the Ocmulgee River.

Such discharges shall be limited as specified below:

There shall be no discharge of floating solids or visible foam in other than trace amounts.

These discharges shall remain as described above. If the Director determines that water quality standards are not being met as the result of these discharges and so notifies the permittee in writing, the permittee shall take all reasonable steps to prevent the discharge from causing water quality standards to be exceeded in the receiving water.

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10. During the period beginning effective date and lasting through November 30, 2006, the permittee is authorized to discharge from outfall(s) serial number(s) 13 and 14 - Emergency Overflows to Lake Juliette (Low Volume Wastes) from Units 1 and 2 Wastewater Basin and Units 3 and 4 Wastewater Basin.

Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitations				Monitoring Requirements		
	Mass Based		Concentration Based (mg/l)				
	Daily Avg.	Daily Max.	Daily Avg.	Daily Max.	Measurement Frequency*	Sample Type	Sample Location
Flow-m^3Day (MGD)	-	-	-	-	-	-	-
Total Suspended Solids (TSS)	-	-	30	100	2/Month	Grab	Overflow
Oil and Grease (O & G)	-	-	15	20	2/Month	Grab	Overflow

The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored twice per month by grab sampling.*

There shall be no discharge of floating solids or visible foam in other than trace amounts.

* Monitoring for TSS, O&G, and pH is required only when an overflow is occurring.

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B. SCHEDULE OF COMPLIANCE

1. The permittee shall achieve compliance with the effluent limitations specified for discharges in accordance with the following schedule:

Effluent limitations are effective upon issuance of this permit.

2. No later than 14 calendar days following a date identified in the above schedule of compliance, the permittee shall submit either a report of progress or, in the case of specific actions being required by identified dates, a written notice of compliance or noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

Note: EPD as used herein means the Environmental Protection Division of the Department of Natural Resources.

C. MONITORING AND REPORTING

1. Representative Sampling

Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge.

2. Reporting

Monitoring results obtained during the previous three months shall be summarized for each month and reported on an Operation Monitoring Report (Form WQ 1.45). Forms other than Form WQ 1.45 may be used upon approval by EPD. These forms and any other required reports and information shall be completed, signed and certified by a principal executive officer or ranking elected official, or by a duly authorized representative of that person, and submitted to the Division, postmarked no later than the 21st day of the month following the reporting period. Signed copies of these and all other reports required herein shall be submitted to the following address:

Georgia Environmental Protection Division
Industrial Wastewater Program
4220 International Parkway
Suite 101
Atlanta, Georgia 30354

All instances of noncompliance not reported under Part I. B. and C. and Part II. A. shall be reported at the time the operation monitoring report is submitted.

3. Definitions

a. The "daily average" discharge means the total discharge by weight during a calendar month divided by the number of days in the month that the production or commercial facility was operating. Where less than daily sampling is required by this permit, the daily average discharge shall be determined by the summation of all the measured daily discharges by weight divided by the number of days sampled during the calendar month when the measurements were made.

b. The "daily maximum" discharge means the total discharge by weight during any calendar day.

c. The "daily average" concentration means the arithmetic average of all the daily determinations of concentrations made during a calendar month. Daily determinations of concentration made using a composite sample shall be the concentration of the composite sample.

d. The "daily maximum" concentration means the daily determination of concentration for any calendar day.

e. For the purpose of this permit, a calendar day is defined as any consecutive 24-hour period.

f. "Bypass" means the intentional diversion of waste streams from any portion of a treatment facility.

g. "Severe property damage" means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

4. Test Procedures

Monitoring must be conducted according to test procedures approved pursuant to 40 CFR Part 136 unless other test procedures have been specified in this permit.

5. Recording of Results

For each measurement or sample taken pursuant to the requirements of this permit, the permittee shall record the following information:

a. The exact place, date, and time of sampling or measurements, and the person(s) performing the sampling or the measurements;

b. The dates the analyses were performed, and the person(s) who performed the analyses;

c. The analytical techniques or methods used; and

d. The results of all required analyses.

6. Additional Monitoring by Permittee

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit, using approved analytical methods as specified above, the results of such monitoring shall be included in the calculation and reporting of the values required in the Operation Monitoring Report Form (WQ 1.45). Such increased monitoring frequency shall also be indicated. The Division may require by written notification more frequent monitoring of other pollutants not required in this permit.

7. Records Retention

The permittee shall retain records of all monitoring information, including all records of analyses performed, calibration and maintenance of instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least three (3) years from the date of the sample, measurement, report or application. This period may be extended by request of the Division at any time.

8. Penalties

The Federal Clean Water Act and the Georgia Water Quality Control Act provide that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit, makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance shall, upon conviction, be punished by a fine or by imprisonment, or by both. The Federal Clean Water Act and the Georgia Water Quality Control Act also provide procedures for imposing civil penalties which may be levied for violations of the Act, any permit condition or limitation established pursuant to the Act, or negligently or intentionally failing or refusing to comply with any final or emergency order of the Director of the Division.

A. MANAGEMENT REQUIREMENTS

1. Change in Discharge

a. Advance notice to the Division shall be given of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. Any anticipated facility expansions, production increases, or process modifications must be reported by submission of a new NPDES permit application or, if such changes will not violate the effluent limitations specified in this permit, by notice to the Division of such changes. Following such notice, the permit may be modified to specify and limit any pollutants not previously limited.

b. All existing manufacturing, commercial, mining, and silviculture dischargers shall notify the Division as soon as it is known or there is reason to believe that any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant not limited in the permit, if that discharge will exceed (I) 100 μg/l, (ii) five times the maximum concentration reported for that pollutant in the permit application, or (iii) 200 μg/l for acrolein and acrylonitrile, 500 μg/l for 2,4 dinitrophenol and for 2-methyl-4-6-dinitrophenol, or 1 mg/l antimony.

c. All existing manufacturing, commercial, mining, and silvicultural dischargers shall notify the Division as soon as it is known or there is reason to believe that any activity has occurred or will occur which would result in any discharge on a nonroutine or infrequent basis, of any toxic pollutant not limited in the permit, if that discharge will exceed (I) 500 μg/l, (ii) ten times the maximum concentration reported for that pollutant in the permit application, or (iii) 1 mg/l antimony.

2. Noncompliance Notification

If, for any reason, the permittee does not comply with, or will be unable to comply with any effluent limitation specified in this permit, the permittee shall provide the Division with an oral report within 24 hours from the time the permittee becomes aware of the circumstances followed by a written report within five (5) days of becoming aware of such condition. The written submission shall contain the following information:

a. A description of the discharge and cause of noncompliance; and

b. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

3. Facilities Operation

The permittee shall at all times maintain in good working order and operate as efficiently as possible all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

4. Adverse Impact

The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment, including such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying discharge.

5. Bypassing

a. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Division at least 10 days (if possible) before the date of the bypass. The permittee shall submit notice of any unanticipated bypass with an oral report within 24 hours from the time the permittee becomes aware of the circumstances followed by a written report within five (5) days of becoming aware of such condition. The written submission shall contain the following information:

1. A description of the discharge and cause of noncompliance; and

2. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

b. Any diversion or bypass of facilities covered by this permit is prohibited, except (I) where unavoidable to prevent loss of life, personal injury, or severe property damage; (ii) 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 the permittee could have installed adequate back-up equipment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance); and (iii) the permittee submitted a notice as required above. The permittee shall operate the treatment works, including the treatment plant and total sewer system, to minimize discharge of the pollutants listed in Part I of this permit from combined sewer overflows or bypasses. Upon written notification by the Division, the permittee may be required to submit a plan and schedule for reducing bypasses, overflows, and infiltration in the system.

6. Sludge Disposal Requirements

Hazardous sludge shall be disposed of in accordance with the regulations and guidelines established by the Division pursuant to the Federal Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA). For land application of nonhazardous sludge, the permittee shall comply with any applicable criteria outlined in the Division's "Guidelines for Land Application of Municipal Sludges." Prior to disposal of sludge by land application, the permittee shall submit a proposal to the Division for approval in accordance with applicable criteria in the Division's "Guidelines for Land Application of Municipal Sludges." Upon evaluation of the permittee's proposal, the Division may require that more stringent control of this activity is required. Upon written notification, the permittee shall submit to the Division for approval, a detailed plan of operation for land application of sludge. Upon approval, the plan will become a part of the NPDES permit. Disposal of nonhazardous sludge by other means, such as landfilling, must be approved by the Division.

7. Sludge Monitoring Requirements

The permittee shall develop and implement procedures to insure adequate year-round sludge disposal. The permittee shall monitor the volume and concentration of solids removed from the plant. Records shall be maintained which document the quantity of solids removed from the plant. The ultimate disposal of solids shall be reported monthly (in the unit of lbs/day) to the Division with the Operation Monitoring Report Forms required under Part I (C)(2) of this permit.

8. Power Failures

Upon the reduction, loss, or failure of the primary source of power to said water pollution control facilities, the permittee shall use an alternative source of power if available to reduce or otherwise control production and/or all discharges in order to maintain compliance with the effluent limitations and prohibitions of this permit.

If such alternative power source is not in existence, and no date for its implementation appears in Part I, the permittee shall halt, reduce or otherwise control production and/or all discharges from wastewater control facilities upon the reduction, loss, or failure of the primary source of power to said wastewater control facilities.

B. RESPONSIBILITIES

1. Right of Entry

The permittee shall allow the Director of the Division, the Regional Administrator of EPA, and/or their authorized representatives, agents, or employees, upon the presentation of credentials:

a. To enter upon the permittee's premises where a regulated activity or facility is located or conducted or where any records are required to be kept under the terms and conditions of this permit; and

b. At reasonable times, to have access to and copy any records required to be kept under the terms and conditions of this permit; to inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and to sample any substance or parameters in any location.

2. Transfer of Ownership or Control

A permit may be transferred to another person by a permittee if:

a. The permittee notifies the Director in writing of the proposed transfer at least thirty (30) days in advance of the proposed transfer;

b. A written agreement containing a specific date for transfer of permit responsibility and coverage between the current and new permittee (including acknowledgement that the existing permittee is liable for violations up to that date, and that the new permittee is liable for violations from that date on) is submitted to the Director at least thirty (30) days in advance of the proposed transfer; and

c. The Director, within thirty (30) days, does not notify the current permittee and the new permittee of the Division's intent to modify, revoke and reissue, or terminate the permit and to require that a new application be filed rather than agreeing to the transfer of the permit.

3. Availability of Reports

Except for data deemed to be confidential under O.C.G.A. § 12-5-26 or by the Regional Administrator of the EPA under the Code of Federal Regulations, Title 40, Part 2, all reports prepared in accordance with the terms of this permit shall be available for public inspection at an office of the Division. Effluent data, permit applications, permittee's names and addresses, and permits shall not be considered confidential.

4. Permit Modification

After written notice and opportunity for a hearing, this permit may be modified, suspended, revoked or reissued in whole or in part during its term for cause including, but not limited to, the following:

a. Violation of any conditions of this permit;

b. Obtaining this permit by misrepresentation or failure to disclose fully all relevant facts;

c. A change in any condition that requires either a temporary or permanent reduction or elimination of the permitted discharge; or

d. To comply with any applicable effluent limitation issued pursuant to the order the United States District Court for the District of Columbia issued on June 8, 1976, in Natural Resources Defense Council, Inc. et.al. v. Russell E. Train, 8 ERC 2120(D.D.C. 1976), if the effluent limitation so issued:

(1) is different in conditions or more stringent than any effluent limitation in the permit; or

(2) controls any pollutant not limited in the permit.

5. Toxic Pollutants

The permittee shall comply with effluent standards or prohibitions established pursuant to Section 307(a) of the Federal Clean Water Act for toxic pollutants, which are present in the discharge within the time provided in the regulations

that establish these standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

6. Civil and Criminal Liability

Nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance.

7. State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation under authority preserved by Section 510 of the Federal Clean Water Act.

8. Water Quality Standards

Nothing in this permit shall be construed to preclude the modification of any condition of this permit when it is determined that the effluent limitations specified herein fail to achieve the applicable State water quality standards.

9. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations.

10. Expiration of Permit

Permittee shall not discharge after the expiration date. In order to receive authorization to discharge beyond the expiration date, the permittee shall submit such information, forms, and fees as are required by the agency authorized to issue permits no later than 180 days prior to the expiration date.

11. Contested Hearings

Any person who is aggrieved or adversely affected by an action of the Director of the Division shall petition the Director for a hearing within thirty (30) days of notice of such action.

12. Severability

The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

13. Best Management Practices

The permittee will implement best management practices to control the discharge of hazardous and/or toxic materials from ancillary manufacturing activities. Such activities include, but are not limited to, materials storage areas, in-plant transfer, process and material handling areas; loading and unloading operations; plant site runoff; and sludge and waste disposal areas.

14. Need to Halt or Reduce Activity Not a Defense

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.

15. Duty to Provide Information

a. The permittee shall furnish to the Director of the Division, within a reasonable time, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or to determine compliance with this permit. The permittee shall also furnish upon request copies of records required to be kept by this permit.

b. When the permittee becomes aware that it failed to submit any relevant facts in a permit application or submitted incorrect information in a permit application or any report to the Director, it shall promptly submit such facts and information.

26. Upset Provisions

Provisions of 40 CFR 122.41(n)(1)-(4), regarding "Upset" shall be applicable to any civil, criminal, or administrative proceeding brought to enforce this permit.

A. PREVIOUS PERMITS

1. All previous State water quality permits issued to this facility, whether for construction or operation, are hereby revoked by the issuance of this permit. This action is taken to assure compliance with the Georgia Water Quality Control Act, as amended, and the Federal Clean Water Act, as amended. Receipt of the permit constitutes notice of such action. The conditions, requirements, terms and provisions of this permit authorizing discharge under the National Pollutant Discharge Elimination System govern discharges from this facility.

B. SPECIAL REQUIREMENTS

1. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

2. Any metal cleaning wastes generated will be contained for further treatment or disposal in a manner to permit compliance at time of discharge (O3I, Chemical Cleaning Wastes) with requirements listed below or disposed of in a manner approved by the Division. This applies to any preoperational chemical cleaning of metal process equipment also. The treatment and disposal procedures shall be discussed in the flow monitoring and characterization submittal.

3. The quantity of pollutants discharged (03I, Chemical Cleaning Wastes) in metal cleaning waste shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentrations listed below. All effluent characteristics shall be monitored 1/week by grab sampling when a discharge is occurring.

Effluent Characteristic	Discharge Limitation (mg/l)	
	Daily Average	Daily Maximum
Total Suspended Solids	30	100
Oil and Grease	15	20
Copper	1.0	1.0
Iron	1.0	1.0

4. Neither free available chlorine (FAC) nor total residual chlorine (TRC) may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Director that the units in a particular location cannot operate at or below this level of chlorination. The permittee has demonstrated the need to continuously chlorinate the service water system to control asiatic clams. The present intent is to chlorinate the service water periodically from April through October, five days per month for 24 hours per day at an initial level of 1.0 mg/l FAC. Other months, longer durations, and lower FAC levels may be used. This chlorination practice will result occasionally in the discharge of FAC or TRC from each cooling tower simultaneously and for more than 2 hours per day. The permittee must reduce the chlorine discharge if possible and has performed a study to determine the minimum practicable chlorine levels,

frequencies and duration of continuous chlorination for the service water system to adequately control asiatic clams.

5. In accordance with 40 CFR 423.11(k), the free available chlorine (FAC) average means the average over any individual chlorine release period of 2 hours per day per unit. The FAC maximum is the instantaneous maximum which may occur at any time. Further, the permittee will develop a system for monitoring and recording total time of FAC and TRC discharges. The results shall be reported in a suitably concise form.

6. In accordance with 40 CFR 423.13(d)(3), the permittee shall certify every two years in the flow characterization study that no priority pollutant other than chromium or zinc is above detectable limits in outfall 01A, 01C, 01D, 05 and 06 (cooling tower blowdowns or overflows). This certification may be based on manufacturers' certifications or engineering calculations.

7. In the event that waste streams for various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled by this permit shall not exceed the specified limitations for that source.

8. The Director may modify any effluent limitation upon request of the permittee if such limitation is covered by an approved variance or by an amendment to the Federal Clean Water Act.

9. Once every two years, the permittee shall submit to the Director flow monitoring and characterization information regarding the various waste streams.

10. All sewage treatment plants (STP) must be properly operated and maintained. This applies to 03A No. 2 STP, 03B No. 4 STP, and 03C, No. 1 STP.

11. Summary of flow characterization study requirements from preceding pages.

    a. Metal cleaning waste treatment and disposal procedures.

    b. Flow determination of various waste streams.

    c. Cooling tower blowdown priority pollutant certification per 40 CFR 423.13(d)(3).

12. The provisions of 40 CFR 122.41(l)(6)(iii) regarding waiver of the 5 day written report required by Part II.A.2. and Part II.A.5 of this permit shall be applicable and may be implemented on a case-by-case basis by EPD for noncompliances which are orally reported by the permittee within 24 hours of discovery of the noncompliance condition.

13. The Division recognizes the inherent analytical variability in approved test methods and procedures and further agrees that such issues can be raised by the permittee as a defense in an enforcement action.

14. Upon approval of the Director, the permittee shall, on a case-by-case basis, be able to utilize alternative analytical methods, conversion factors, methodology, procedures, or new technologies, to ensure that the biomonitoring and toxicity reduction requirements of Part III.C. and the testing/reporting requirements of the permit are adequately addressed.

15. If the results for a given sample are such that a parameter is not detected at or above the method detection limit or reporting limit, a value of zero will be reported for that sample and the method detection limit or reporting limit will also be reported. Such sample shall be deemed to be in compliance with the permit limit.

16. The best management practices plan for "Macrofouling and Biofouling Control" dated July 26, 2001 is hereby approved and incorporated in this permit. The plan may be modified upon written approval by the Division.

17. The permittee is authorized to discharge storm water from the outfalls identified in Part I, Section A. of this permit provided that these discharges do not cause violations of State water quality standards in the receiving streams.

C. BIOMONITORING AND TOXICITY REDUCTION REQUIREMENTS

In order to determine whether the permittee is discharging wastes in concentrations or combinations which may have an adverse impact on the State's water quality, the Division can require the permittee to conduct a biomonitoring program.

If toxicity is believed to be present in the permittee's effluent, the Division may require the permittee to develop a biomonitoring screening program according to the following schedule:

1. Within 90 days of Division notification a screening program study plan detailing the test methodology and test organisms shall be submitted for conducting a forty-eight hour static acute test of the final effluent.

   Note: If residual chlorine is present in the final effluent from a treatment and/or disinfection process, a prechlorinated or dechlorinated sample will be tested.

2. Within 90 days of Division approval of the study plan, the permittee shall conduct and submit the results of the forty-eight hour static acute test.

The Division will then review the results of the forty-eight hour static acute test. If the test criteria specified in the study plan are exceeded, then the permittee shall within 90 days of written notification by the Division repeat steps 1. and 2. above replacing the forty-eight hour static acute test with the ninety-six hour test.

The Division will then review the results of the ninety-six hour test. If the criteria* detailed in the ninety-six hour test indicates toxicity, then the permittee shall within 90 days of written notification by the Division submit to the Division a plan to reduce the toxicity of the effluent. Within 270 days of Division approval of this plan, the permittee shall implement the plan and initiate follow-up biomonitoring of the effluent in accordance with the approved toxicity reduction plan. The toxicity reduction plan shall not be complete until the permittee meets the criteria detailed in the ninety-six hour test plan.

If there are substantial composition changes in the permittee's effluent, the permittee may be required to repeat the forty-eight hour static acute test upon notification by the Division. Unless otherwise advised, the permittee shall perform biomonitoring of the effluent as provided in C. 1. and 2. above, at a minimum of once every three years upon notification by the Division. On a case specific basis, chronic toxicity testing procedures may be required. Upon approval by the Division, all of the plans will become part of the requirements of this permit.

*The 96 hour criteria shall define toxicity as a greater than 10% mortality of the exposed test organisms in 96 hours or less when the test solution contains volumes of effluent and dilution water proportional to the plant daily average flow and the 7Q10 flow of the receiving stream, as determined using test procedures and methods, and statistical methods for evaluating test results, developed by the permittee and approved by the Division pursuant to this section or revised pursuant to Part III. B. 14. above.

Georgia Power

Mark S. Berry
Vice President
Environmental &
Natural Resources

241 Ralph McGill Boulevard NE
Atlanta, GA 30308-3374
404 506 7777 tel
404 506 2488 fax
msberry@southernco.com

January 30, 2018
CERTIFIED MAIL

Mr. Richard E. Dunn, Director
Environmental Protection Division
2 Martin Luther King Jr. Drive SE
Suite 1456 East, Floyd Tower
Atlanta, Georgia 30334-9000

RE: Plant Scherer
NPDES Permit No. GA00035564
Application for Permit Renewal

Dear Mr. Dunn:

Attached is an updated NPDES permit renewal application package for Georgia Power Company's Plant Scherer facility, located in Juliette, Georgia.

The updated application package includes the following supporting documentation:

- EPA NPDES Application Forms 1 and 2C
- Water flow diagrams for:
  a. Current Configuration; and
  b. Ash Pond Closure Configuration
- USGS 7.5 minute topographic location map showing the facility
- NPDES Industrial Permit Application Addendum
- 316(b) Cooling Water Intake Structure information
- Effluent Limitations Guidelines Applicability Timing

As noted above, ash pond dewatering activities are likely to occur during the permit term. As such, the application package includes two flow diagrams. The first diagram depicts the current wastewater flow schematic; this flow pattern is expected to remain until commencement of ash pond closure. The second diagram represents the wastewater flow schematic necessary to support ash pond closure and during the dewatering process. Georgia Power will notify EPD in advance of ash pond dewatering activities in accordance with NPDES Permit.

If you need additional information or have any questions regarding this application package, please contact Jean Brown at jeabrown@southernco.com or 404-506-6360.

Sincerely,

Mark S. Berry, Vice President
Environmental & Natural Resources

Attachments

xc: Ms. Audra Dickson, EPD Industrial Permitting Unit, with attachments

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 7
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Michael W. Sole MWS-6

bc:	Michelle Kroh	with attachments
	Christine Ridley	"
	E.F. Veira	"
	Jean Brown	"
	Scott Smith	"

File: POW 07-01-11-00

Please print or type in the unshaded areas only.

Form Approved. OMB No. 2040-0086.

FORM 1 GENERAL

U.S. ENVIRONMENTAL PROTECTION AGENCY
GENERAL INFORMATION
Consolidated Permits Program
(Read the "General Instructions" before starting.)

I. EPA I.D. NUMBER: F GAD000612796

LABEL ITEMS
- I. EPA I.D. NUMBER
- III. FACILITY NAME
- V. FACILITY MAILING ADDRESS
- VI. FACILITY LOCATION

PLEASE PLACE LABEL IN THIS SPACE

GENERAL INSTRUCTIONS
If a preprinted label has been provided, affix it in the designated space. Review the information carefully: if any of it is incorrect, cross through it and enter the correct data in the appropriate fill-in area below. Also, if any of the preprinted data is absent *(the area to the left of the label space lists the information that should appear)*, please provide it in the proper fill-in area(s) below. If the label is complete and correct, you need not complete Items I, III, V, and VI *(except VI-B which must be completed regardless)*. Complete all items if no label has been provided. Refer to the instructions for detailed item descriptions and for the legal authorizations under which this data is collected.

II. POLLUTANT CHARACTERISTICS

INSTRUCTIONS: Complete A through J to determine whether you need to submit any permit application forms to the EPA. If you answer "yes" to any questions, you must submit this form and the supplemental form listed in the parenthesis following the question. Mark "X" in the box in the third column if the supplemental form is attached. If you answer "no" to each question, you need not submit any of these forms. You may answer "no" if your activity is excluded from permit requirements; see Section C of the instructions. See also, Section D of the instructions for definitions of **bold-faced terms**.

SPECIFIC QUESTIONS	Mark "X" YES	NO	FORM ATTACHED
A. Is this facility a **publicly owned treatment works** which results in a **discharge to waters of the U.S.?** (FORM 2A)		X	
B. Does or will this facility *(either existing or proposed)* include a **concentrated animal feeding operation** or **aquatic animal production facility** which results in a **discharge to waters of the U.S.?** (FORM 2B)		X	
C. Is this a facility which currently results in **discharges to waters of the U.S.** other than those described in A or B above? (FORM 2C)	X		X
D. Is a proposed facility *(other than those described in A or B above)* which will result in a **discharge** to waters of the U.S.? (FORM 2D)		X	
E. Does or will this facility treat, store, or dispose of **hazardous wastes?** (FORM 3)		X	
F. Do you or will you inject at this facility industrial or municipal effluent below the lowermost stratum containing, within one quarter mile of the well bore, underground sources of drinking water? (FORM 4)		X	
G. Do you or will you inject at this facility any produced water or other fluids which are brought to the surface in connection with conventional oil or natural gas production, inject fluids used for enhanced recovery of oil or natural gas, or inject fluids for storage of liquid hydrocarbons? (FORM 4)		X	
H. Do you or will you inject at this facility fluids for special processes such as mining of sulfur by the Frasch process, solution mining of minerals, in situ combustion of fossil fuel, or recovery of geothermal energy? (FORM 4)		X	
I. Is this facility a proposed **stationary source** which is one of the 28 industrial categories listed in the instructions and which will potentially emit 100 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an attainment area? (FORM 5)		X	
J. Is this facility a proposed **stationary source** which is NOT one of the 28 industrial categories listed in the instructions and which will potentially emit 250 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an attainment area? (FORM 5)		X	

III. NAME OF FACILITY

1 SKIP: PLANT SCHERER

IV. FACILITY CONTACT

A. NAME & TITLE *(last, first, & title)*	B. PHONE *(area code & no.)*
2 BERRY, MARK S., VP, ENVIRONMENTAL & NATURAL RESOURCES	(404) 506-7777

V. FACILITY MAILING ADDRESS

A. STREET OR P.O. BOX: 3 241 RALPH MCGILL BLVD., N.E.

B. CITY OR TOWN	C. STATE	D. ZIP CODE
4 ATLANTA	GA	30308

VI. FACILITY LOCATION

A. STREET, ROUTE NO. OR OTHER SPECIFIC IDENTIFIER: 5 10986 HIGHWAY 87

B. COUNTY NAME: MONROE

C. CITY OR TOWN	D. STATE	E. ZIP CODE	F. COUNTY CODE *(if known)*
6 JULIETTE	GA	31046	N/A

CONTINUE ON REVERSE

CONTINUED FROM THE FRONT

VII. SIC CODES *(4-digit, in order of priority)*

A. FIRST	B. SECOND
4911 (specify) Generation of electricity	(specify) N/A

C. THIRD	D. FOURTH
(specify) N/A	(specify) N/A

VIII. OPERATOR INFORMATION

A. NAME: GEORGIA POWER COMPANY

B. Is the name listed in Item VIII-A also the owner? ☑ YES ☐ NO

C. STATUS OF OPERATOR *(Enter the appropriate letter into the answer box; if "Other," specify.)*
F = FEDERAL; S = STATE; P = PRIVATE; M = PUBLIC *(other than federal or state)*; O = OTHER *(specify)*
P (specify)

D. PHONE *(area code & no.)*: A (404) 506-6526

E. STREET OR P.O. BOX: 241 RALPH MCGILL BLVD., N.E.

F. CITY OR TOWN: ATLANTA

G. STATE: GA

H. ZIP CODE: 30308

IX. INDIAN LAND: Is the facility located on Indian lands? ☐ YES ☑ NO

X. EXISTING ENVIRONMENTAL PERMITS

A. NPDES *(Discharges to Surface Water)*	D. PSD *(Air Emissions from Proposed Sources)*
N GA0035564	P N/A
B. UIC *(Underground Injection of Fluids)*	**E. OTHER** *(specify)*
U N/A	N/A (specify)
C. RCRA *(Hazardous Wastes)*	**E. OTHER** *(specify)*
R N/A	N/A (specify)

XI. MAP

Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers, and other surface water bodies in the map area. See instructions for precise requirements.

XII. NATURE OF BUSINESS *(provide a brief description)*

Generation of electricity through combustion of fossil fuels.

*Plant Scherer is jointly owned by: Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, Florida Power and Light, Jacksonville Electric Authority, Gulf Power Company and the City of Dalton.

XIII. CERTIFICATION *(see instructions)*

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the 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.

A. NAME & OFFICIAL TITLE *(type or print)*	B. SIGNATURE	C. DATE SIGNED
Mark Berry, V.P., Env & Nat Resources	Mark Berry	01/29/18

COMMENTS FOR OFFICIAL USE ONLY

C

EPA Form 3510-1 (8-90)

Please print or type in the unshaded areas only

EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796

Form Approved.
OMB No. 2040-0086
Approval expires 3-31-98

FORM 2C NPDES

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR PERMIT TO DISCHARGE WASTEWATER
EXISTING MANUFACTURING, COMMERCIAL, MINING AND SILVICULTURE OPERATIONS
Consolidated Permits Program

I. OUTFALL LOCATION

For each outfall, list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

A. OUTFALL NUMBER (*list*)	B. LATITUDE			C. LONGITUDE			D. RECEIVING WATER (*name*)
	1. DEG	2. MIN	3. SEC	1. DEG	2. MIN	3. SEC	
01	33.00	5.00	6.00	-83.00	46.00	44.00	Ocmulgee River
02	33.00	4.00	18.00	-83.00	47.00	45.00	Berry Creek

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (*e.g., for certain mining activities*), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

1. OUTFALL NO. (*list*)	2. OPERATION(S) CONTRIBUTING FLOW		3. TREATMENT		
	a. OPERATION (*list*)	b. AVERAGE FLOW (*include units*)	a. DESCRIPTION	b. LIST CODES FROM TABLE 2C-1	
01	Final Plant Discharge	14,052 gpm	19,000 gpm (maximum)	2F*	4A
	Stormwater				
01A	Cooling Tower Blowdown	11,700 gpm	13,000 gpm (maximum)	2F*	4A
	Units 1-4				
01B	Ash Transport Bleedoff	6,500 gpm	19,753 gpm (maximum)		4A
01C	Unit 3 Cooling Tower Overflow	**	15,820 gpm (maximum)	2F*	4A
	and Basin Drain				
01D	Unit 4 Cooling Tower Overflow	**	15,820 gpm (maximum)	2F*	4A
	and Basin Drain				
01E	NPDES Basin Minimum Flow	**	2,238 gpm (maximum)	2F*	4A
02	Detention Pond (I-Pond)	451 gpm	22,266 gpm	1-U	4A
	Stormwater		(10 yr - 24 hr rainfall event)		
02A	Detention Pond Bottom Drain	**		1-U	4A
02B	Fire Training Runoff	**			4A
02C	NPDES Basin Emergency Overflow	**		2F*	4A
	Stormwater			1-U	
	* During periods of chlorination				
	** Intermittent or emergency				
	discharge				

OFFICIAL USE ONLY (*effluent guidelines sub-categories*)

Please print or type in the unshaded areas only.

EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796

Form Approved.
OMB No. 2040-0086.
Approval expires 3-31-98.

FORM 2C NPDES

EPA

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR PERMIT TO DISCHARGE WASTEWATER
EXISTING MANUFACTURING, COMMERCIAL, MINING AND SILVICULTURE OPERATIONS
Consolidated Permits Program

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A. OUTFALL NUMBER (*list*)	B. LATITUDE			C. LONGITUDE			D. RECEIVING WATER (*name*)
	1. DEG.	2. MIN.	3. SEC.	1. DEG.	2. MIN.	3. SEC.	
03							Internal

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (*e.g., for certain mining activities*), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

1. OUTFALL NO. (*list*)	2. OPERATION(S) CONTRIBUTING FLOW		3. TREATMENT		
	a. OPERATION (*list*)	b. AVERAGE FLOW (*include units*)	a. DESCRIPTION	b. LIST CODES FROM TABLE 2C-1	
03	Ash Transport Water	38,500 gpm	50,000 gpm (maximum)	4C	4A
	Stormwater			1U	2K
03A	No. 2 Sewage Treatment Plant	2 gpm	120 gpm (maximum)	3A	4C
				2F	
03B	No. 4 Sewage Treatment Plant	1 gpm	17 gpm (maximum)	3A	4C
				2F	
03C	No 1. Sewage Treatment Plant	2 gpm	30 gpm (maximum)	3A	4C
				2F	
03D	Coal Pile Runoff Basin	2,361 gpm	5,300 gpm (maximum)	4C	1U
03E	Wastewater Basins - Units 1-4	4,623 gpm	15,000 gpm (maximum)	4C	
03F	Low Volume Wastes- Units 1-4	5,388 gpm	8,600 gpm (maximum)	4C	
03G	Tractor Garage	1 gpm	500 gpm (maximum)	4C	
03H	Coal Pile Runoff	561 gpm	12,800 gpm (maximum)	4C	1U
03I	Chemical Cleaning Wastes	**	12,800 gpm (maximum)	2K	4C
				2C	1U
	** Intermittent or emergency				
	discharge				

OFFICIAL USE ONLY (*effluent guidelines sub-categories*)

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EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796

Form Approved.
OMB No. 2040-0086.
Approval expires 3-31-98.

FORM 2C NPDES

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR PERMIT TO DISCHARGE WASTEWATER
EXISTING MANUFACTURING, COMMERCIAL, MINING AND SILVICULTURE OPERATIONS
Consolidated Permits Program

I. OUTFALL LOCATION

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A. OUTFALL NUMBER (*list*)	B. LATITUDE			C. LONGITUDE			D. RECEIVING WATER (*name*)
	1. DEG.	2. MIN.	3. SEC.	1. DEG.	2. MIN.	3. SEC.	
03							Internal

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (*e.g., for certain mining activities*), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

1. OUTFALL NO. (*list*)	2. OPERATION(S) CONTRIBUTING FLOW		3. TREATMENT		
	a. OPERATION (*list*)	b. AVERAGE FLOW (*include units*)	a. DESCRIPTION	b. LIST CODES FROM TABLE 2C-1	
03J	Flue Gas Desulfurization Wastewater	100 gpm	1300 gpm (max)	4C	1U
	Stormwater				
03K	Limestone and Gypsum Handling Area	**		4C	1U
	Runoff				
03L	CCR Landfill Leachate	50 gpm	500 gpm (max)	4C	1U
03M	Non-Chemical Metal Cleaning Wastes	**	500 gpm (max)	4C	1U
	** Intermittent or emergency				
	discharge				

OFFICIAL USE ONLY (*effluent guidelines sub-categories*)

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EPA I D NUMBER (*copy from Item 1 of Form 1*): GAD000612796

Form Approved.
OMB No 2040-0086
Approval expires 3-31-98

FORM 2C NPDES

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR PERMIT TO DISCHARGE WASTEWATER
EXISTING MANUFACTURING, COMMERCIAL, MINING AND SILVICULTURE OPERATIONS
Consolidated Permits Program

I. OUTFALL LOCATION

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A. OUTFALL NUMBER (*list*)	B. LATITUDE			C. LONGITUDE			D. RECEIVING WATER (*name*)
	1 DEG.	2 MIN.	3 SEC.	1 DEG.	2 MIN.	3 SEC.	
04,05,06,07	33.00	3.00	14.00	-83.00	48.00	26.00	Lake Juliette

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (*e.g., for certain mining activities*), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

1. OUTFALL NO. (*list*)	2. OPERATION(S) CONTRIBUTING FLOW		3. TREATMENT		
	a. OPERATION (*list*)	b. AVERAGE FLOW (*include units*)	a. DESCRIPTION	b. LIST CODES FROM TABLE 2C-1	
04	Service Water Final Discharge	1,527 gpm	42,000 gpm (maximum)	2F*	4A
04A	Service Water Return	**	42,000 gpm (maximum)	2F*	4A
04B	Service Water Minimum Flow	1,527 gpm	66,000 gpm (maximum)	2F*	4A
05	Unit 1 Cooling Tower Overflow and Basin Drain	**	15,820 gpm (maximum)	2F*	4A
06	Low Volume Wastes- Units 1-4 and Basin Drain	**	15,820 gpm (maximum)	2F*	4A
07	Settling Pond Emergency Overflow	**	57,000 gpm (maximum)	1U	4A
	Stormwater			2K	
	* During periods of chlorination				
	** Intermittent or emergency discharge				

OFFICIAL USE ONLY (*effluent guidelines sub-categories*)

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EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796

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OMB No. 2040-0086
Approval expires 3-31-98

FORM 2C NPDES

EPA

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR PERMIT TO DISCHARGE WASTEWATER
EXISTING MANUFACTURING, COMMERCIAL, MINING AND SILVICULTURE OPERATIONS
Consolidated Permits Program

I. OUTFALL LOCATION

For each outfall, list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

A. OUTFALL NUMBER (*list*)	B. LATITUDE			C. LONGITUDE			D. RECEIVING WATER (*name*)
	1. DEG	2. MIN	3. SEC	1. DEG	2. MIN	3. SEC	
08,09,10,12	33.00	3.00	14.00	-83.00	48.00	26.00	Lake Juliette
11	33.00	2.00	51.00	-83.00	44.00	21.00	Ocmulgee River

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (*e.g., for certain mining activities*), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) The average flow contributed by each operation; and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

1. OUTFALL NO. (*list*)	2. OPERATION(S) CONTRIBUTING FLOW		3. TREATMENT		
	a. OPERATION (*list*)	b. AVERAGE FLOW (*include units*)	a. DESCRIPTION	b. LIST CODES FROM TABLE 2C-1	
08	Employee Carwash	7 gpm	325 gpm (maximum)		4A
	Stormwater				
09	Service Water Pump Seal Water	65 gpm	78 gpm (maximum)		4A
10	Service Water Screen Backwash	510 gpm	765 gpm (maximum)		4A
11	River Intake Pump Seal Water	100 gpm	100 gpm (maximum)	2F*	4A
12	Condensate, Filtered Water and	**	2,536 gpm (maximum)	2F*	4A
	Potable Water Tank Overflow				
	Stormwater				
	* During periods of chlorination				
	** Intermittent or emergency				
	discharge				

OFFICIAL USE ONLY (*effluent guidelines sub-categories*)

Please print or type in the unshaded areas only

EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796

Form Approved.
OMB No. 2040-0086.
Approval expires 3-31-98.

FORM 2C NPDES

EPA

U.S. ENVIRONMENTAL PROTECTION AGENCY
APPLICATION FOR PERMIT TO DISCHARGE WASTEWATER
EXISTING MANUFACTURING, COMMERCIAL, MINING AND SILVICULTURE OPERATIONS
Consolidated Permits Program

I. OUTFALL LOCATION

For each outfall, list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

A. OUTFALL NUMBER (*list*)	B. LATITUDE			C. LONGITUDE			D. RECEIVING WATER (*name*)
	1. DEG	2. MIN	3. SEC.	1. DEG	2. MIN.	3. SEC.	
13,14	33.00	3.00	14.00	-83.00	48.00	26.00	Lake Juliette

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (*e.g., for certain mining activities*), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) All operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) The average flow contributed by each operation, and (3) The treatment received by the wastewater. Continue on additional sheets if necessary.

1. OUTFALL NO. (*list*)	2. OPERATION(S) CONTRIBUTING FLOW		3. TREATMENT		
	a. OPERATION (*list*)	b. AVERAGE FLOW (*include units*)	a. DESCRIPTION	b. LIST CODES FROM TABLE 2C-1	
13	Units 1 & 2 Wastewater Basin	**	4,300 gpm (maximum)		4A
	Emergency Overflow				
14	Units 3 & 4 Wastewater Basin	**	4,300 gpm (maximum)		4A
	Emergency Overflow				
	** Intermittent or emergency				
	discharge				

OFFICIAL USE ONLY (*effluent guidelines sub-categories*)

CONTINUED FROM THE FRONT

C. Except for storm runoff, leaks, or spills, are any of the discharges described in Items II-A or B intermittent or seasonal?

☐ YES (*complete the following table*) ☐ NO (*go to Section III*)

1. OUTFALL NUMBER (*list*)	2. OPERATION(s) CONTRIBUTING FLOW (*list*)	3. FREQUENCY		4. FLOW				
		a. DAYS PER WEEK (*specify average*)	b. MONTHS PER YEAR (*specify average*)	a. FLOW RATE (*in mgd*)		B. TOTAL VOLUME (*specify with units*)		C. DURATION (*in days*)
				1. LONG TERM AVERAGE	2. MAXIMUM DAILY	1. LONG TERM AVERAGE	2. MAXIMUM DAILY	
	See Attachement 1 for intermittent discharges Analysis of overflows and emergency dicharges are submitted with the Operating Monitoring Reports							

III. PRODUCTION

A. Does an effluent guideline limitation promulgated by EPA under Section 304 of the Clean Water Act apply to your facility?

☒ YES (*complete Item III-B*) ☐ NO (*go to Section IV*)

B. Are the limitations in the applicable effluent guideline expressed in terms of production (*or other measure of operation*)?

☐ YES (*complete Item III-C*) ☒ NO (*go to Section IV*)

C. If you answered "yes" to Item III-B, list the quantity which represents an actual measurement of your level of production, expressed in the terms and units used in the applicable effluent guideline, and indicate the affected outfalls.

1. AVERAGE DAILY PRODUCTION			2. AFFECTED OUTFALLS (*list outfall numbers*)
a. QUANTITY PER DAY	b. UNITS OF MEASURE	c. OPERATION, PRODUCT, MATERIAL, ETC. (*specify*)	

IV. IMPROVEMENTS

A. Are you now required by any Federal, State or local authority to meet any implementation schedule for the construction, upgrading or operations of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders, and grant or loan conditions.

☐ YES (*complete the following table*) ☑ NO (*go to Item IV-B*)

1. IDENTIFICATION OF CONDITION, AGREEMENT, ETC.	2. AFFECTED OUTFALLS		3. BRIEF DESCRIPTION OF PROJECT	4. FINAL COMPLIANCE DATE	
	a. NO.	b. SOURCE OF DISCHARGE		a. REQUIRED	b. PROJECTED

B. OPTIONAL: You may attach additional sheets describing any additional water pollution control programs (*or other environmental projects which may affect your discharges*) you now have underway or which you plan. Indicate whether each program is now underway or planned, and indicate your actual or planned schedules for construction.

☐ MARK "X" IF DESCRIPTION OF ADDITIONAL CONTROL PROGRAMS IS ATTACHED

EPA I.D. NUMBER (*copy from Item 1 of Form 1*)
GAD000612796

CONTINUED FROM PAGE 2

V. INTAKE AND EFFLUENT CHARACTERISTICS

A, B, & C: See instructions before proceeding – Complete one set of tables for each outfall – Annotate the outfall number in the space provided. NOTE: Tables V-A, V-B, and V-C are included on separate sheets numbered V-1 through V-9.

D. Use the space below to list any of the pollutants listed in Table 2c-3 of the instructions, which you know or have reason to believe is discharged or may be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it to be present and report any analytical data in your possession.

1. POLLUTANT	2. SOURCE	1. POLLUTANT	2. SOURCE
None			

VI. POTENTIAL DISCHARGES NOT COVERED BY ANALYSIS

Is any pollutant listed in Item V-C a substance or a component of a substance which you currently use or manufacture as an intermediate or final product or byproduct?

☐ YES (*list all such pollutants below*) ☑ NO (*go to Item VI-B*)

CONTINUED FROM THE FRONT

VII. BIOLOGICAL TOXICITY TESTING DATA

Do you have any knowledge or reason to believe that any biological test for acute or chronic toxicity has been made on any of your discharges or on a receiving water in relation to your discharge within the last 3 years?

☐ YES (*identify the test(s) and describe their purposes below*) ☑ NO (*go to Section VIII*)

VIII. CONTRACT ANALYSIS INFORMATION

Were any of the analyses reported in Item V performed by a contract laboratory or consulting firm?

☑ YES (*list the name, address, and telephone number of, and pollutants analyzed by, each such laboratory or firm below*) ☐ NO (*go to Section IX*)

A. NAME	B. ADDRESS	C. TELEPHONE (*area code & no.*)	D. POLLUTANTS ANALYZED (*list*)
Pace Analytical Services, LLC	110 Technology Parkway Peachtree Corners, GA 30092	770-734-4200	All except pH, temperature, sulfite and low level mercury
Pace Analytical Services, LLC	2225 Riverside Drive Asheville, NC 28804	828-254-7176	Low level mercury

IX. CERTIFICATION

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.

A. NAME & OFFICIAL TITLE (*type or print*)	B. PHONE NO. (*area code & no.*)
Mark Berry, Vice President, Environmental & Natural Resources	(404) 506-7777
C. SIGNATURE: Mark Berry	D. DATE SIGNED: 01/29/18

INTERMITTENT FLOW DESCRIPTIONS

Attachment 1 for Form 2C page 2

Outfalls 01C, 01D, 05, and 06 – Cooling Tower Overflow / Basin Drain

Overflows from cooling towers may occur infrequently during equipment malfunction or emergency conditions. The estimated overflow discharge (15,820 gpm) is the design make-up water flow. Draining of the cooling tower basins may occur during unit outages. The frequency is dependent on unit operation and is estimated at twice per year.

Outfall 01E - NPDES Basin Minimum Flow

NPDES system minimum flows typically occur during periods of unit outages or cooling tower biocide treatment due to reduced cooling tower blow-down. The effluent is service water with a maximum discharge of 2,238 gpm.

Outfall 02A - I-Pond Bottom Drain

Discharges from the Detention (I-Pond) through the bottom drain could occur if necessary to perform dike, dam, or pond maintenance.

Outfall 02B - Fire Training Runoff

Discharges of filtered water used for fire training purposes may occur during the year due to classes conducted on site.

Outfall 02C - NPDES Basin Emergency Overflow

The normal discharge for the NPDES basin is through Outfall 01. In the event of equipment malfunctions or emergency conditions, the basin may discharge though this outfall. Past events have been infrequent and of short duration.

Outfall 03I - Chemical Metal Cleaning Wastes

Boiler and turbine cleaning wastes are usually treated with sodium hydroxide or lime to a pH sufficient to precipitate the iron and copper suspended in solution. The water is then pumped to the ash pond via the wastewater basin. Boiler cleaning is infrequent and turbine cleaning is typically once per year. Rainwater is also pumped out of the chemical cleaning basin into the Units 1 & 2 wastewater basin.

Outfall 03K – Limestone and Gypsum Handling Area Runoff

Discharges from storm water runoff from the limestone stockpile and gypsum handing area will depend on frequency and volume of rainfall events. These will flow to the Coal Pile Runoff Pond which is pumped to the Ash Pond.

Outfall 03M – Non-Chemical Metal Cleaning Wastes

Precipitators may be washed down during outages. This water will now be sent to the new Coal Pile Runoff Treatment System (in the 2019 flow schematic). The frequency is dependent on unit operation and is estimated at once per year.

Outfall 07 - Settling Pond Emergency Overflow

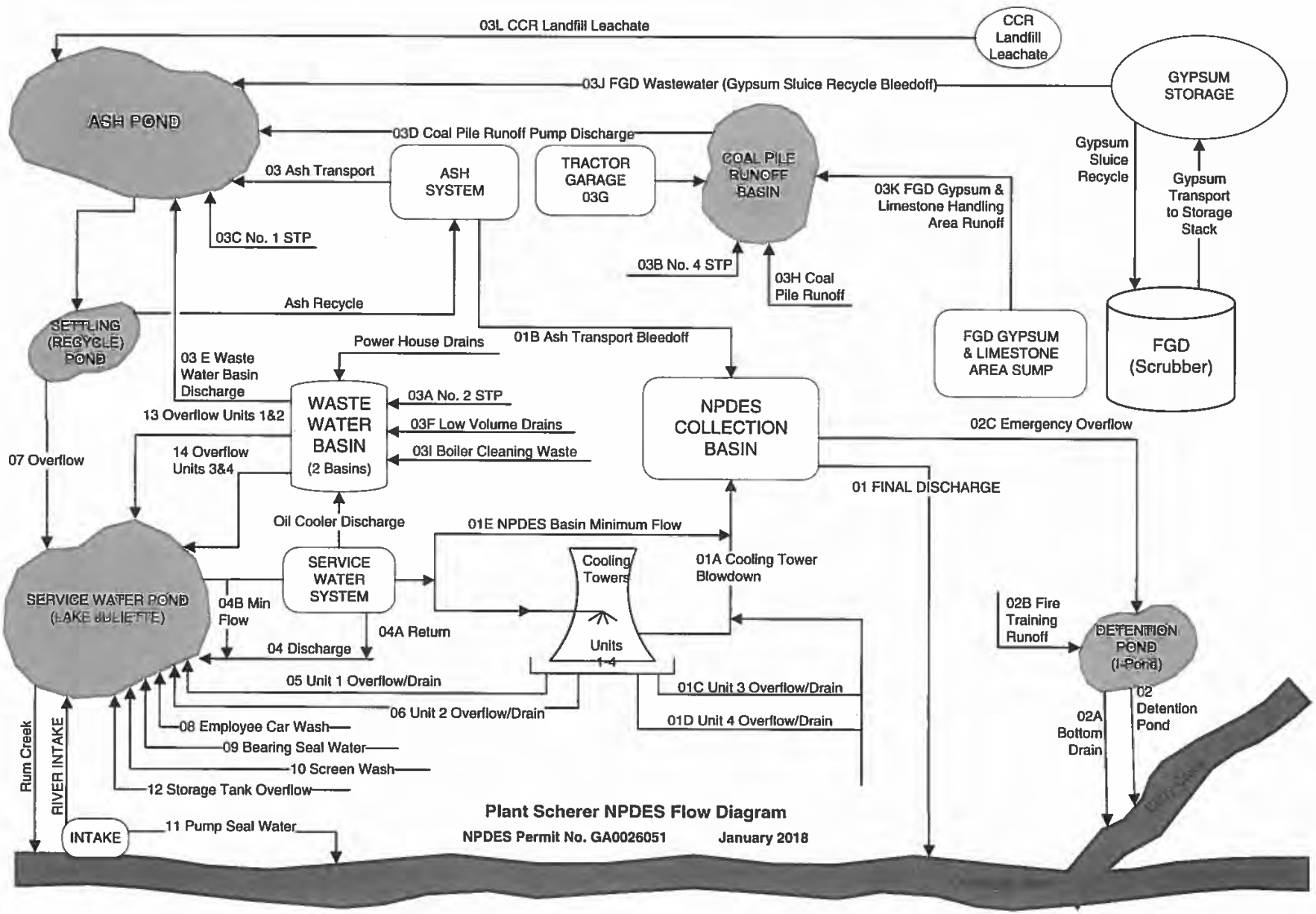
The normal settling pond discharge is through the ash transport bleed-off system. Discharges from the emergency overflow should only occur during periods of equipment malfunction, heavy rainfall, or emergency conditions. Overflow volume is variable with an estimated maximum of 57,000 gpm.

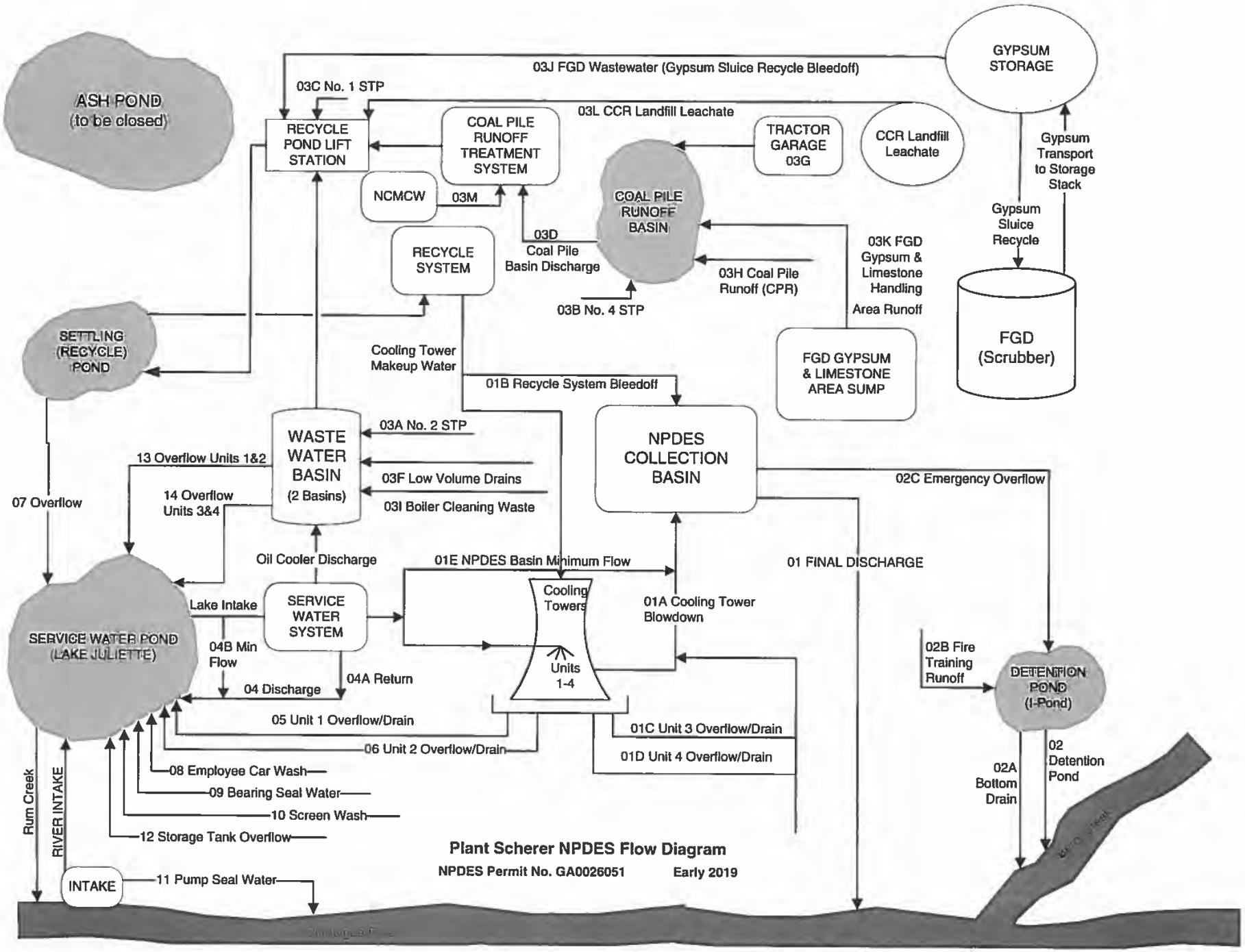
Outfall 12 - Condensate/Filtered Water/Potable Water Tank Overflows to Lake Juliette (Service Water Pond)

Storage tanks could overflow during abnormal operations. These infrequent overflows would consist of condensate, demineralized water, filtered water, or potable water. An overflow is typically less than 100 gpm and of short duration.

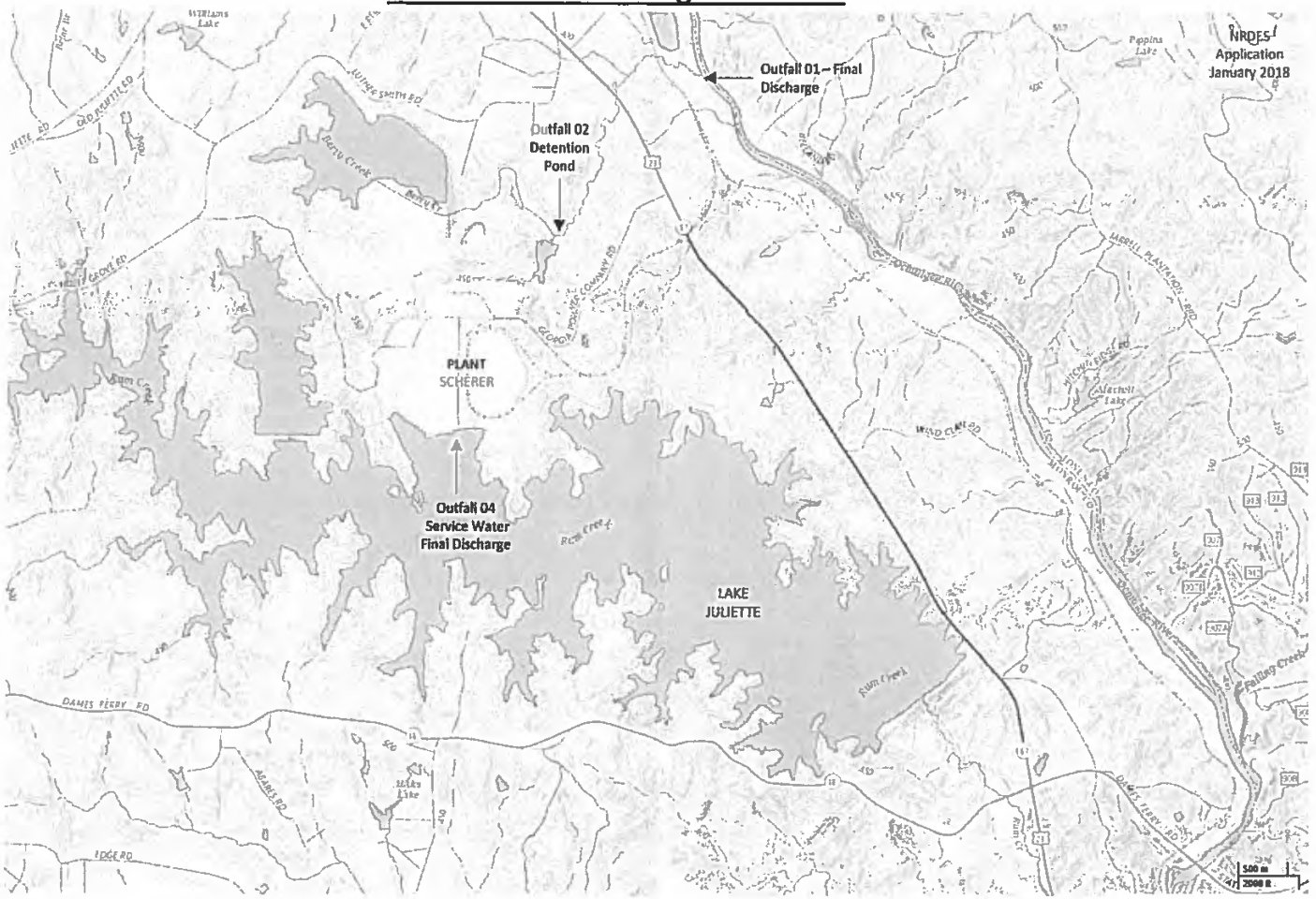
Outfall 13 and 14 - Waste Water Basin Emergency Overflow

Discharges could occur from equipment malfunctions or emergency conditions. An emergency portable pump is in standby mode to reduce the likelihood of an overflow.


03L CCR Landfill Leachate
CCR Landfill Leachate
03J FGD Wastewater (Gypsum Sluice Recycle Bleedoff)
GYPSUM STORAGE
ASH POND
03D Coal Pile Runoff Pump Discharge
03 Ash Transport
ASH SYSTEM
TRACTOR GARAGE 03G
COAL PILE RUNOFF BASIN
Gypsum Sluice Recycle
Gypsum Transport to Storage Stack
03K FGD Gypsum & Limestone Handling Area Runoff
03C No. 1 STP
03B No. 4 STP
03H Coal Pile Runoff
Ash Recycle
SETTLING (RECYCLE) POND
Power House Drains
01B Ash Transport Bleedoff
FGD GYPSUM & LIMESTONE AREA SUMP
FGD (Scrubber)
03 E Waste Water Basin Discharge
WASTE WATER BASIN (2 Basins)
03A No. 2 STP
13 Overflow Units 1&2
03F Low Volume Drains
03I Boiler Cleaning Waste
NPDES COLLECTION BASIN
02C Emergency Overflow
07 Overflow
14 Overflow Units 3&4
01 FINAL DISCHARGE
Oil Cooler Discharge
01E NPDES Basin Minimum Flow
SERVICE WATER SYSTEM
Cooling Towers
01A Cooling Tower Blowdown
SERVICE WATER POND (LAKE JULIETTE)
04B Min Flow
02B Fire Training Runoff
DETENTION POND (I-Pond)
04A Return
04 Discharge
Units 1-4
05 Unit 1 Overflow/Drain
01C Unit 3 Overflow/Drain
06 Unit 2 Overflow/Drain
01D Unit 4 Overflow/Drain
02A Bottom Drain
02 Detention Pond
08 Employee Car Wash
09 Bearing Seal Water
10 Screen Wash
12 Storage Tank Overflow
Rum Creek
RIVER INTAKE
INTAKE
11 Pump Seal Water
Plant Scherer NPDES Flow Diagram
NPDES Permit No. GA0026051 January 2018


ASH POND
(to be closed)
GYPSUM STORAGE
03J FGD Wastewater (Gypsum Sluice Recycle Bleedoff)
03C No. 1 STP
03L CCR Landfill Leachate
RECYCLE POND LIFT STATION
COAL PILE RUNOFF TREATMENT SYSTEM
TRACTOR GARAGE 03G
CCR Landfill Leachate
Gypsum Transport to Storage Stack
NCMCW
03M
COAL PILE RUNOFF BASIN
Gypsum Sluice Recycle
RECYCLE SYSTEM
03D Coal Pile Basin Discharge
03K FGD Gypsum & Limestone Handling Area Runoff
03H Coal Pile Runoff (CPR)
03B No. 4 STP
FGD (Scrubber)
SETTLING (RECYCLE) POND
Cooling Tower Makeup Water
FGD GYPSUM & LIMESTONE AREA SUMP
01B Recycle System Bleedoff
WASTE WATER BASIN (2 Basins)
03A No. 2 STP
NPDES COLLECTION BASIN
13 Overflow Units 1&2
03F Low Volume Drains
02C Emergency Overflow
07 Overflow
14 Overflow Units 3&4
03I Boiler Cleaning Waste
Oil Cooler Discharge
01E NPDES Basin Minimum Flow
01 FINAL DISCHARGE
Cooling Towers
SERVICE WATER SYSTEM
Lake Intake
01A Cooling Tower Blowdown
SERVICE WATER POND (LAKE JULIETTE)
02B Fire Training Runoff
DETENTION POND (I-Pond)
04B Min Flow
04A Return
04 Discharge
Units 1-4
05 Unit 1 Overflow/Drain
01C Unit 3 Overflow/Drain
06 Unit 2 Overflow/Drain
01D Unit 4 Overflow/Drain
02 Detention Pond
02A Bottom Drain
08 Employee Car Wash
09 Bearing Seal Water
10 Screen Wash
12 Storage Tank Overflow
Rum Creek
RIVER INTAKE
INTAKE
11 Pump Seal Water
Plant Scherer NPDES Flow Diagram
NPDES Permit No. GA0026051 Early 2019

Plant Scherer Discharge Locations



USGS 7.5 Minute - East Juliette Quadrangle

PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages. SEE INSTRUCTIONS.

EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796 (Scherer)

V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 01

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	3. UNITS (*specify if blank*) a. CONCEN-TRATION	3. UNITS b. MASS	4. INTAKE (*optional*) a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	4. INTAKE a. LONG TERM AVERAGE VALUE (2) MASS	4. INTAKE b. NO. OF ANALYSES
a. Biochemical Oxygen Demand (*BOD*)	<2.0	<457					1	mg/l	lb/d	<8.0		1
b. Chemical Oxygen Demand (*COD*)	<10	<2282					1	mg/l	lb/d	<10		1
c. Total Organic Carbon (*TOC*)	5.2	1186.6					1	mg/l	lb/d	4.8		1
d. Total Suspended Solids (*TSS*)	5	1140.9					1	mg/l	lb/d	5		1
e. Ammonia (*as N*)	<0.1	<23					1	mg/l	lb/d	<0.1		1
f. Flow	VALUE 19000		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 19.89		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 27.29		VALUE		VALUE		1	°C		VALUE 25.09		1
i. pH	MINIMUM 8.01	MAXIMUM 8.01	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X" a. BELIEVED PRESENT	2. MARK "X" b. BELIEVED ABSENT	3. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	4. UNITS a. CONCEN-TRATION	4. UNITS b. MASS	5. INTAKE (*optional*) a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	5. INTAKE a. LONG TERM AVERAGE VALUE (2) MASS	5. INTAKE b. NO. OF ANALYSES
a. Bromide (24959-67-9)			1.0	228.2					1	mg/l	lb/d	<1.0		1
b. Chlorine, Total Residual			<0.1						1	mg/l		0.1		1
c. Color			30						1	PCU		200		1
d. Fecal Coliform			1600				66.4		3	col/100		800		1
e. Fluoride (16984-48-8)			1.2	273.8					1	mg/l	lb/d	0.31		1
f. Nitrate-Nitrite (*as N*)			1.1	251					1	mg/l	lb/d	0.89		1

ITEM V-B CONTINUED FROM FRONT

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	a. LONG TERM AVERAGE VALUE (2) MASS	b. NO. OF ANALYSES
g. Nitrogen, Total Organic (*as N*)			<0.4	<91.4					1	mg/l	lb/d	<0.4		1
h. Oil and Grease			<6.0	<1369.1					1	mg/l	lb/d	<5.4		1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<45.7					1	mg/l	lb/d	<0.2		1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (*as SO_4*) (14808-79-8)			230	52482					1	mg/l	lb/d	22		1
l. Sulfide (*as S*)			<0.2	<45.7					1	mg/l	lb/d	<0.2		1
m. Sulfite (*as SO_3*) (14265-45-3)			1.28	292.1					1	mg/l	lb/d	1.92		1
n. Surfactants			0.07	16					1	mg/l	lb/d	0.06		1
o. Aluminum, Total (7429-90-5)			0.977	222.9					1	mg/l	lb/d	0.409		1
p. Barium, Total (7440-39-3)			0.140	31.9					1	mg/l	lb/d	0.0239		1
q. Boron, Total (7440-42-8)			0.876	199.9					1	mg/l	lb/d	<0.04		1
r. Cobalt, Total (7440-48-4)			<0.04	<9.13					1	mg/l	lb/d	<0.04		1
s. Iron, Total (7439-89-6)			0.0657	15					1	mg/l	lb/d	0.76		1
t. Magnesium, Total (7439-95-4)			11.5	2624					1	mg/l	lb/d	1.45		1
u. Molybdenum, Total (7439-98-7)			<0.04	<9.13					1	mg/l	lb/d	<0.04		1
v. Manganese, Total (7439-96-5)			0.078	17.8					1	mg/l	lb/d	0.0792		1
w. Tin, Total (7440-31-5)			<0.02	<4.6					1	mg/l	lb/d	<0.02		1
x. Titanium, Total (7440-32-6)			<0.01	<2.3					1	mg/l	lb/d	0.0147		1

EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
GAD000612796 (Scherer)	01

CONTINUED FROM PAGE 3 OF FORM 2-C

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	a. LONG TERM AVERAGE VALUE (2) MASS	b. NO. OF ANALYSES
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<1.2					1	mg/l	lb/day	<0.005		1
2M. Arsenic, Total (7440-38-2)				<0.005	<1.2					1	mg/l	lb/day	<0.005		1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.16					1	mg/l	lb/day	<0.0007		1
5M. Chromium, Total (7440-47-3)				<0.005	<1.2					1	mg/l	lb/day	<0.005		1
6M. Copper, Total (7440-50-8)				0.0657	14.99					1	mg/l	lb/day	<0.005		1
7M. Lead, Total (7439-92-1)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
8M. Mercury, Total (7439-97-6)				0.00258	0.59					1	ug/l	lb/day	<0.005		1
9M. Nickel, Total (7440-02-0)				0.0075	1.7					1	mg/l	lb/day	<0.005		1
10M. Selenium, Total (7782-49-2)				0.0055	1.26					1	mg/l	lb/day	<0.005		1
11M. Silver, Total (7440-22-4)				<0.005	<1.2					1	mg/l	lb/day	<0.005		1
12M. Thallium, Total (7440-28-0)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
13M. Zinc, Total (7440-66-6)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
14M. Cyanide, Total (57-12-5)				<0.02	<4.6					1	mg/l	lb/day	<0.02		1
15M. Phenols, Total				<0.05	<11.41					1	mg/l	lb/day	<0.05		1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<11.41					1	mg/l	lb/day	<0.05		1
2V. Acrylonitrile (107-13-1)				<0.05	<11.41					1	mg/l	lb/day	<0.05		1
3V. Benzene (71-43-2)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
7V. Chlorobenzene (108-90-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
8V. Chlorodibromomethane (124-48-1)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
9V. Chloroethane (75-00-3)				<0.005	<1.14					1	mg/l	lb/day	<0.005		1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
11V. Chloroform (67-66-3)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
12V. Dichlorobromomethane (75-27-4)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
19V. Ethylbenzene (100-41-4)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
20V. Methyl Bromide (74-83-9)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
21V. Methyl Chloride (74-87-3)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1

* Analytical Method Unavailable

CONTINUED FROM PAGE V-4

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
24V. Tetrachloro-ethylene (127-18-4)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
25V. Toluene (108-88-3)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
27V. 1,1,1-Trichloro-ethane (71-55-6)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
28V. 1,1,2-Trichloro-ethane (79-00-5)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
29V Trichloro-ethylene (79-01-6)				<0.002	<0.46					1	mg/l	lb/day	<0.002		1
30V. Trichloro-fluoromethane (75-69-4)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
31V. Vinyl Chloride (75-01-4)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
2A. 2,4-Dichloro-phenol (120-83-2)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
3A. 2,4-Dimethyl-phenol (105-67-9)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<11.41					1	mg/l	lb/day	<0.05		1
5A. 2,4-Dinitro-phenol (51-28-5)				<0.05	<11.41					1	mg/l	lb/day	<0.05		1
6A. 2-Nitrophenol (88-75-5)				<0.05	<11.41					1	mg/l	lb/day	<0.05		1
7A. 4-Nitrophenol (100-02-7)				<0.05	<11.41					1	mg/l	lb/day	<0.05		1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
9A. Pentachloro-phenol (87-86-5)				<0.02	<4.6					1	mg/l	lb/day	<0.02		1
10A. Phenol (108-95-2)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
11A. 2,4,6-Trichloro-phenol (88-05-2)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1

CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	a. LONG TERM AVERAGE VALUE (2) MASS	b. NO. OF ANALYSES
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
2B. Acenaphtylene (208-96-8)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
3B. Anthracene (120-12-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
4B. Benzidine (92-87-5)				<0.08	<18.3					1	mg/l	lb/day	<0.08		1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
18B. Chrysene (218-01-9)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1

CONTINUED FROM PAGE V-6

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<4.6					1	mg/l	lb/day	<0.02		1
24B. Diethyl Phthalate (84-66-2)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
25B. Dimethyl Phthalate (131-11-3)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<4.6					1	mg/l	lb/day	<0.02		1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<4.6					1	mg/l	lb/day	<0.02		1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
31B. Fluoranthene (206-44-0)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
32B. Fluorene (86-73-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
33B. Hexachlorobenzene (118-74-1)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
36B Hexachloroethane (67-72-1)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
37B. Indeno (*1,2,3-cd*) Pyrene (193-39-5)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
38B. Isophorone (78-59-1)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
39B. Naphthalene (91-20-3)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
40B. Nitrobenzene (98-95-3)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1

CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitro-sodiphenylamine (86-30-6)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
44B. Phenanthrene (85-01-8)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
45B. Pyrene (129-00-0)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
46B. 1,2,4-Tri-chlorobenzene (120-82-1)				<0.01	<2.3					1	mg/l	lb/day	<0.01		1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
GAD000612796 (Scherer)	01

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
19P. PCB-1254 (11097-69-1)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
20P. PCB-1221 (11104-28-2)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
21P. PCB-1232 (11141-16-5)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
22P. PCB-1248 (12672-29-6)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
23P. PCB-1260 (11096-82-5)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
24P. PCB-1016 (12674-11-2)				<0.001	<0.23					1	mg/l	lb/day	<0.001		1
25P. Toxaphene (8001-35-2)			X												1

PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages. SEE INSTRUCTIONS.

EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796 (Scherer)

V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO.: 02

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	3. UNITS (*specify if blank*) a. CONCEN-TRATION	3. UNITS b. MASS	4. INTAKE (*optional*) a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	4. INTAKE a. LONG TERM AVERAGE VALUE (2) MASS	4. INTAKE b. NO. OF ANALYSES
a. Biochemical Oxygen Demand (*BOD*)	<2.0	<5.4					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	<10	<2674.1					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	3.9	1043					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	<5	<1337					1	mg/l	lb/d			1
e. Ammonia (*as N*)	<0.10	<27					1	mg/l	lb/d			1
f. Flow	VALUE 22266		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 17.41		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 26.79		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 7.51	MAXIMUM 7.51	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X" a. BELIEVED PRESENT	2. MARK "X" b. BELIEVED ABSENT	3. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	4. UNITS a. CONCEN-TRATION	4. UNITS b. MASS	5. INTAKE (*optional*) a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	5. INTAKE a. LONG TERM AVERAGE VALUE (2) MASS	5. INTAKE b. NO. OF ANALYSES
a. Bromide (24959-67-9)			<1.0	<268					1	mg/l	lb/d			1
b. Chlorine, Total Residual			<0.1						1	mg/l				1
c. Color			20						1	PCU				1
d. Fecal Coliform			90						1	col/100				1
e. Fluoride (16984-48-8)			0.49	131					1	mg/l	lb/d			1
f. Nitrate-Nitrite (*as N*)			2.1	562					1	mg/l	lb/d			1

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ITEM V-B CONTINUED FROM FRONT

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (as N)			<0.40	<107					1	mg/l	lb/d			1
h. Oil and Grease			<6.0	<1605					1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<53.5					1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (as SO_4) (14808-79-8)			51	13638					1	mg/l	lb/d			1
l. Sulfide (as S)			<0.2	<53.5					1	mg/l	lb/d			1
m. Sulfite (as SO_3) (14265-45-3)			1.28	342.3					1	mg/l	lb/d			1
n. Surfactants			0.06	16					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			0.247	66.1					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.0674	18					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			0.38	101.6					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<10.7					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.296	79.2					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			5.99	1601.8					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<10.7					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			0.0455	12.2					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<53.5					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			0.0153	4.1					1	mg/l	lb/d			1

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EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
GAD000612796 (Scherer)	02

CONTINUED FROM PAGE 3 OF FORM 2-C

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<1.34					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<1.34					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.27					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.19					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<1.34					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				0.0075	2					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.27					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.00213	0.57					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				<0.005	<1.34					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<1.34					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<1.34					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.27					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				<0.01	<2.68					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<5.35					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<13.4					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetrachlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<13.4					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<13.4					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<0.54					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<2.68					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.54					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<2.68					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<2.68					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<1.34					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<2.68					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				<0.002	<0.54					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<2.68					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<2.68					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<0.54					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<0.54					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<0.54					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<0.54					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<0.54					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<0.54					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<2.68					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<2.68					1	mg/l	lb/day			1

* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<2.68					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.54					1	mg/l	lb/day			1
24V. Tetrachloroethylene (127-18-4)				<0.002	<0.54					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<0.54					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.54					1	mg/l	lb/day			1
27V. 1,1,1-Trichloroethane (71-55-6)				<0.002	<0.54					1	mg/l	lb/day			1
28V. 1,1,2-Trichloroethane (79-00-5)				<0.002	<0.54					1	mg/l	lb/day			1
29V Trichloroethylene (79-01-6)				<0.002	<0.54					1	mg/l	lb/day			1
30V. Trichlorofluoromethane (75-69-4)				<0.01	<2.68					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<2.68					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<2.68					1	mg/l	lb/day			1
2A. 2,4-Dichlorophenol (120-83-2)				<0.01	<2.68					1	mg/l	lb/day			1
3A. 2,4-Dimethylphenol (105-67-9)				<0.01	<2.68					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<13.4					1	mg/l	lb/day			1
5A. 2,4-Dinitrophenol (51-28-5)				<0.05	<13.4					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<13.4					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<13.4					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<2.68					1	mg/l	lb/day			1
9A. Pentachlorophenol (87-86-5)				<0.02	<5.35					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<2.68					1	mg/l	lb/day			1
11A. 2,4,6-Trichlorophenol (88-05-2)				<0.01	<2.68					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<2.68					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<2.68					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<2.68					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<21.4					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<2.68					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<2.68					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<2.68					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<2.68					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<2.68					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<2.68					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<2.68					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<2.68					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<2.68					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<2.68					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<2.68					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<2.68					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<2.68					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<2.68					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<2.68					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<2.68					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<2.68					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<2.68					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<5.35					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<2.68					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131-11-3)				<0.01	<2.68					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<2.68					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<5.35					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<5.35					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<2.68					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<2.68					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<2.68					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<2.68					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<2.68					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<2.68					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<2.68					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<2.68					1	mg/l	lb/day			1
37B. Indeno (1,2,3-cd) Pyrene (193-39-5)				<0.01	<2.68					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<2.68					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<2.68					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<2.68					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<2.68					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<2.68					1	mg/l	lb/day			1

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CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitro-sodiphenylamine (86-30-6)				<0.01	<2.68					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<2.68					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<2.68					1	mg/l	lb/day			1
46B. 1,2,4-Tri-chlorobenzene (120-82-1)				<0.01	<2.68					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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GAD000612796 (Scherer)	02

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.27					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.27					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.27					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.27					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.27					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.27					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.27					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

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PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages. SEE INSTRUCTIONS.

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V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 04

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	3. UNITS (*specify if blank*) a. CONCEN-TRATION	3. UNITS b. MASS	4. INTAKE (*optional*) a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	4. INTAKE a. LONG TERM AVERAGE VALUE (2) MASS	4. INTAKE b. NO. OF ANALYSES
a. Biochemical Oxygen Demand (*BOD*)	<8.0	<4035					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	<10	<5044					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	3.1	1564					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	<5	<2522					1	mg/l	lb/d			1
e. Ammonia (*as N*)	0.40	201.8					1	mg/l	lb/d			1
f. Flow	VALUE 42,000		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 18.43		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 26.99		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 8.14	MAXIMUM 8.14	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X" a. BELIEVED PRESENT	2. MARK "X" b. BELIEVED ABSENT	3. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	4. UNITS a. CONCEN-TRATION	4. UNITS b. MASS	5. INTAKE (*optional*) a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	5. INTAKE a. LONG TERM AVERAGE VALUE (2) MASS	5. INTAKE b. NO. OF ANALYSES
a. Bromide (24959-67-9)			<1.0	<504					1	mg/l	lb/d			1
b. Chlorine, Total Residual			0.2						1	mg/l				1
c. Color			40						1	PCU				1
d. Fecal Coliform			6						1	col/100				1
e. Fluoride (16984-48-8)			0.23	116					1	mg/l	lb/d			1
f. Nitrate-Nitrite (*as N*)			0.40	201.8					1	mg/l	lb/d			1

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1. POLLUTANT AND CAS NO. (if available)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (if available)		c. LONG TERM AVRG. VALUE (if available)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (as N)			<0.40	<201.8					1	mg/l	lb/d			1
h. Oil and Grease			<6.0	<3062					1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<101					1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (as SO_4) (14808-79-8)			19	9584					1	mg/l	lb/d			1
l. Sulfide (as S)			<0.2	<101					1	mg/l	lb/d			1
m. Sulfite (as SO_3) (14265-45-3)			1.92	968.45					1	mg/l	lb/d			1
n. Surfactants			<0.05	<25.2					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			<0.1	<50.4					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.026	13.1					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			<0.04	<20.2					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	20.2					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.272	137.2					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			1.99	1003.8					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<20.2					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			0.154	77.7					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<10.1					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			<0.01	<5.04					1	mg/l	lb/d			1

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Scherer 2018 Outfall 04

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EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
GAD000612796 (Scherer)	04

CONTINUED FROM PAGE 3 OF FORM 2-C

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<2.52					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<2.52					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.504					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.35					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<2.52					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				0.0658	33.19			0.0264	25.11	3	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.002	<1.01					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				<0.0005	<0.25					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				<0.005	<2.52					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<2.52					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<2.52					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.504					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				0.116	58.5					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<10.1					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<25.2					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<25.2					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<25.2					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<1.01					1	mg/l	lb/day			1
4V. Bis (*Chloro-methyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<5.04					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<1.01					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<5.04					1	mg/l	lb/day			1
8V. Chlorodi-bromomethane (124-48-1)				<0.01	<5.04					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<2.52					1	mg/l	lb/day			1
10V. 2-Chloro-ethylvinyl Ether (110-75-8)				<0.01	<5.04					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				<0.002	<1.01					1	mg/l	lb/day			1
12V. Dichloro-bromomethane (75-27-4)				<0.01	<5.04					1	mg/l	lb/day			1
13V. Dichloro-difluoromethane (75-71-8)				<0.01	<5.04					1	mg/l	lb/day			1
14V. 1,1-Dichloro-ethane (75-34-3)				<0.002	<1.01					1	mg/l	lb/day			1
15V. 1,2-Dichloro-ethane (107-06-2)				<0.002	<1.01					1	mg/l	lb/day			1
16V. 1,1-Dichloro-ethylene (75-35-4)				<0.002	<1.01					1	mg/l	lb/day			1
17V. 1,2-Dichloro-propane (78-87-5)				<0.002	<1.01					1	mg/l	lb/day			1
18V. 1,3-Dichloro-propylene (542-75-6)				<0.002	<1.01					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<1.01					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<5.04					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<5.04					1	mg/l	lb/day			1

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* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<5.04					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<1.01					1	mg/l	lb/day			1
24V. Tetrachloro-ethylene (127-18-4)				<0.002	<1.01					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<1.01					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<1.01					1	mg/l	lb/day			1
27V. 1,1,1-Trichloro-ethane (71-55-6)				<0.002	<1.01					1	mg/l	lb/day			1
28V. 1,1,2-Trichloro-ethane (79-00-5)				<0.002	<1.01					1	mg/l	lb/day			1
29V Trichloro-ethylene (79-01-6)				<0.002	<1.01					1	mg/l	lb/day			1
30V. Trichloro-fluoromethane (75-69-4)				<0.01	<5.04					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<5.04					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<5.04					1	mg/l	lb/day			1
2A. 2,4-Dichloro-phenol (120-83-2)				<0.01	<5.04					1	mg/l	lb/day			1
3A. 2,4-Dimethyl-phenol (105-67-9)				<0.01	<5.04					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<25.2					1	mg/l	lb/day			1
5A. 2,4-Dinitro-phenol (51-28-5)				<0.05	<25.2					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<25.2					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<25.2					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<5.04					1	mg/l	lb/day			1
9A. Pentachloro-phenol (87-86-5)				<0.02	<10.1					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<5.04					1	mg/l	lb/day			1
11A. 2,4,6-Trichloro-phenol (88-05-2)				<0.01	<5.04					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<5.04					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<5.04					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<5.04					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<40.4					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<5.04					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<5.04					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<5.04					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<5.04					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<5.04					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<5.04					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<5.04					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<5.04					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<5.04					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<5.04					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<5.04					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<5.04					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<5.04					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<5.04					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<5.04					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<5.04					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<5.04					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<5.04					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<10.1					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<5.04					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131 -11-3)				<0.01	<5.04					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<5.04					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<10.1					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<10.1					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<5.04					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<5.04					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<5.04					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<5.04					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<5.04					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<5.04					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<5.04					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<5.04					1	mg/l	lb/day			1
37B. Indeno (1,2,3-cd) Pyrene (193-39-5)				<0.01	<5.04					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<5.04					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<5.04					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<5.04					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<5.04					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<5.04					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitrosodiphenylamine (86-30-6)				<0.01	<5.04					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<5.04					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<5.04					1	mg/l	lb/day			1
46B. 1,2,4-Trichlorobenzene (120-82-1)				<0.01	<5.04					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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GAD000612796 (Scherer)	04

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.504					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.504					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.504					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.504					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.504					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.504					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.504					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

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PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages.
SEE INSTRUCTIONS.

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V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 05

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT						3. UNITS (*specify if blank*)		4. INTAKE (*optional*)		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand (*BOD*)	<2.0	<380					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	<10	<1900					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	5.7	1083					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	11	2090					1	mg/l	lb/d			1
e. Ammonia (*as N*)	<0.10	<19					1	mg/l	lb/d			1
f. Flow	VALUE 15,820		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 18.90		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 29.16		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 8.12	MAXIMUM 8.12	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)			<1.0	<190.0					1	mg/l	lb/d			1
b. Chlorine, Total Residual			0.7						1	mg/l				1
c. Color			250						1	PCU				1
d. Fecal Coliform			<4						1	col/100				1
e. Fluoride (16984-48-8)			0.58	110.2					1	mg/l	lb/d			1
f. Nitrate-Nitrite (*as N*)			1.3	247.0					1	mg/l	lb/d			1

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (*as N*)			<0.4	<75.0					1	mg/l	lb/d			1
h. Oil and Grease			<6.0	<1140.0					1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<38.0					1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (*as SO_4*) (14808-79-8)			32	6079.7					1	mg/l	lb/d			1
l. Sulfide (*as S*)			<0.2	<38.0					1	mg/l	lb/d			1
m. Sulfite (*as SO_3*) (14265-45-3)			2.56	486.4					1	mg/l	lb/d			1
n. Surfactants			0.07	13.3					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			0.234	44.46					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.0791	15.03					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			0.094	17.86					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<7.6					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.454	86.26					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			5.32	1010.76					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<7.6					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			0.249	47.31					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<38.0					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			0.0111	2.11					1	mg/l	lb/d			1

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GAD000612796 (Scherer)	05

CONTINUED FROM PAGE 3 OF FORM 2-C

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<0.95					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<0.95					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.19					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.133					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<0.95					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				0.237	45.03					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.19					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.00113	0.215					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				0.030	5.7					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<0.95					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<0.95					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.19					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				<0.01	<1.9					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<3.8					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<9.5					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<9.5					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<9.5					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<0.38					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<1.9					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.38					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<1.9					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<1.9					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<0.95					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<1.9					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				0.0045	0.855					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<1.9					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<1.9					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<0.38					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<0.38					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<0.38					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<0.38					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<0.38					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<0.38					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<1.9					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<1.9					1	mg/l	lb/day			1

* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<1.9					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.38					1	mg/l	lb/day			1
24V. Tetrachloroethylene (127-18-4)				<0.002	<0.38					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<0.38					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.38					1	mg/l	lb/day			1
27V. 1,1,1-Trichloroethane (71-55-6)				<0.002	<0.38					1	mg/l	lb/day			1
28V. 1,1,2-Trichloroethane (79-00-5)				<0.002	<0.38					1	mg/l	lb/day			1
29V Trichloroethylene (79-01-6)				<0.002	<0.38					1	mg/l	lb/day			1
30V. Trichlorofluoromethane (75-69-4)				<0.01	<1.9					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<1.9					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<1.9					1	mg/l	lb/day			1
2A. 2,4-Dichlorophenol (120-83-2)				<0.01	<1.9					1	mg/l	lb/day			1
3A. 2,4-Dimethylphenol (105-67-9)				<0.01	<1.9					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<9.45					1	mg/l	lb/day			1
5A. 2,4-Dinitrophenol (51-28-5)				<0.05	<9.45					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<9.45					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<9.45					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<1.9					1	mg/l	lb/day			1
9A. Pentachlorophenol (87-86-5)				<0.02	<3.8					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<1.9					1	mg/l	lb/day			1
11A. 2,4,6-Trichlorophenol (88-05-2)				<0.01	<1.9					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<1.9					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<1.9					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<1.9					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<15.2					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<1.9					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<1.9					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<1.9					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<1.9					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<1.9					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<1.9					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<1.9					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<1.9					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<1.9					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<1.9					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<1.9					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<1.9					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<1.9					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<1.9					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<1.9					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<1.9					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<1.9					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<1.9					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<3.8					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<1.9					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131-11-3)				<0.01	<1.9					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<1.9					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<3.8					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<3.8					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<1.9					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<1.9					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<1.9					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<1.9					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<1.9					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<1.9					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<1.9					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<1.9					1	mg/l	lb/day			1
37B. Indeno (*1,2,3-cd*) Pyrene (193-39-5)				<0.01	<1.9					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<1.9					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<1.9					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<1.9					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<1.9					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<1.9					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitrosodiphenylamine (86-30-6)				<0.01	<1.9					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<1.9					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<1.9					1	mg/l	lb/day			1
46B. 1,2,4-Trichlorobenzene (120-82-1)				<0.01	<1.9					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
GAD000612796 (Scherer)	05

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.19					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.19					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.19					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.19					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.19					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.19					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.19					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

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PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages.
SEE INSTRUCTIONS.

EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796 (Scherer)

V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 06

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT							3. UNITS (*specify if blank*)		4. INTAKE (*optional*)		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand (*BOD*)	<2.0	<380					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	26	4940					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	8.6	1634					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	20	3800					1	mg/l	lb/d			1
e. Ammonia (*as N*)	<0.10	<19					1	mg/l	lb/d			1
f. Flow	VALUE 15,820		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 18.90		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 29.28		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 7.99	MAXIMUM 7.99	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)			<1.0	<1.9					1	mg/l	lb/d			1
b. Chlorine, Total Residual			0.4						1	mg/l				1
c. Color			100						1	PCU				1
d. Fecal Coliform			<4						1	col/100				1
e. Fluoride (16984-48-8)			0.44	83.6					1	mg/l	lb/d			1
f. Nitrate-Nitrite (*as N*)			1.9	361.0					1	mg/l	lb/d			1

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (*as N*)			0.82	155.8					1	mg/l	lb/d			1
h. Oil and Grease			<5.6	<1064.0					1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<38.0					1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (*as SO_4*) (14808-79-8)			45	8549.6					1	mg/l	lb/d			1
l. Sulfide (*as S*)			<0.2	<38.0					1	mg/l	lb/d			1
m. Sulfite (*as SO_3*) (14265-45-3)			3.20	608.0					1	mg/l	lb/d			1
n. Surfactants			0.07	133.0					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			0.450	85.5					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.105	19.9					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			0.149	28.3					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<7.6					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.887	168.5					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			7.010	1331.8					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<7.6					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			0.546	103.7					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<3.8					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			0.0231	4.39					1	mg/l	lb/d			1

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GAD000612796 (Scherer)	06

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PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<0.95					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<0.95					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.19					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.133					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<0.95					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				0.452	85.9					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.19					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.00113	0.215					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				0.0465	8.34					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<0.95					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<0.95					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.19					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				<0.01	<1.9					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<3.8					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<9.5					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<9.5					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<9.5					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<0.38					1	mg/l	lb/day			1
4V. Bis (*Chloro-methyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<1.9					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.38					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<1.9					1	mg/l	lb/day			1
8V. Chlorodi-bromomethane (124-48-1)				<0.01	<1.9					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<0.95					1	mg/l	lb/day			1
10V. 2-Chloro-ethylvinyl Ether (110-75-8)				<0.01	<1.9					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				<0.002	<0.38					1	mg/l	lb/day			1
12V. Dichloro-bromomethane (75-27-4)				<0.01	<1.9					1	mg/l	lb/day			1
13V. Dichloro-difluoromethane (75-71-8)				<0.01	<1.9					1	mg/l	lb/day			1
14V. 1,1-Dichloro-ethane (75-34-3)				<0.002	<0.38					1	mg/l	lb/day			1
15V. 1,2-Dichloro-ethane (107-06-2)				<0.002	<0.38					1	mg/l	lb/day			1
16V. 1,1-Dichloro-ethylene (75-35-4)				<0.002	<0.38					1	mg/l	lb/day			1
17V. 1,2-Dichloro-propane (78-87-5)				<0.002	<0.38					1	mg/l	lb/day			1
18V. 1,3-Dichloro-propylene (542-75-6)				<0.002	<0.38					1	mg/l	lb/day		•	1
19V. Ethylbenzene (100-41-4)				<0.002	<0.38					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<1.9					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<1.9					1	mg/l	lb/day			1

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* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<1.9					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.38					1	mg/l	lb/day			1
24V. Tetrachloro-ethylene (127-18-4)				<0.002	<0.38					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<0.38					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.38					1	mg/l	lb/day			1
27V. 1,1,1-Trichloro-ethane (71-55-6)				<0.002	<0.38					1	mg/l	lb/day			1
28V. 1,1,2-Trichloro-ethane (79-00-5)				<0.002	<0.38					1	mg/l	lb/day			1
29V Trichloro-ethylene (79-01-6)				<0.002	<0.38					1	mg/l	lb/day			1
30V. Trichloro-fluoromethane (75-69-4)				<0.01	<1.9					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<1.9					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<1.9					1	mg/l	lb/day			1
2A. 2,4-Dichloro-phenol (120-83-2)				<0.01	<1.9					1	mg/l	lb/day			1
3A. 2,4-Dimethyl-phenol (105-67-9)				<0.01	<1.9					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<9.5					1	mg/l	lb/day			1
5A. 2,4-Dinitro-phenol (51-28-5)				<0.05	<9.5					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<9.5					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<9.5					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<1.9					1	mg/l	lb/day			1
9A. Pentachloro-phenol (87-86-5)				<0.02	<3.8					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<1.9					1	mg/l	lb/day			1
11A. 2,4,6-Trichloro-phenol (88-05-2)				<0.01	<1.9					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<1.9					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<1.9					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<1.9					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<15.2					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<1.9					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<1.9					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<1.9					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<1.9					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<1.9					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<1.9					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<1.9					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-60-1)				<0.01	<1.9					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<1.9					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<1.9					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<1.9					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<1.9					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<1.9					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<1.9					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<1.9					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<1.9					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<1.9					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<1.9					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<3.8					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<1.9					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131 -11-3)				<0.01	<1.9					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<1.9					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<3.8					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<3.8					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<1.9					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<1.9					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<1.9					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<1.9					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<1.9					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<1.9					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<1.9					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<1.9					1	mg/l	lb/day			1
37B. Indeno (*1,2,3-cd*) Pyrene (193-39-5)				<0.01	<1.9					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<1.9					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<1.9					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<1.9					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<1.9					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<1.9					1	mg/l	lb/day			1

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitro-sodiphenylamine (86-30-6)				<0.01	<1.9					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<1.9					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<1.9					1	mg/l	lb/day			1
46B. 1,2,4-Tri-chlorobenzene (120-82-1)				<0.01	<1.9					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.19					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.19					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.19					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.19					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.19					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.19					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.19					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

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PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages. SEE INSTRUCTIONS.

EPA I D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796 (Scherer)

V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 07

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT						3. UNITS (*specify if blank*)		4. INTAKE (*optional*)		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand (*BOD*)	<8.0	<5476.4					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	<10	<6845.5					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	3.5	<2395.9					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	6	<4107.3					1	mg/l	lb/d			1
e. Ammonia (*as N*)	<0.10	<68.45					1	mg/l	lb/d			1
f. Flow	VALUE 57,000		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 20.16		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 28.05		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 7.41	MAXIMUM 7.41	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)			1.3	889.9					1	mg/l	lb/d			1
b. Chlorine, Total Residual			<0.1						1	mg/l				1
c. Color			15						1	PCU				1
d. Fecal Coliform			94						1	col/100				1
e. Fluoride (16984-48-8)			1.8	1232.2					1	mg/l	lb/d			1
f. Nitrate-Nitrite (*as N*)			0.78	533.95					1	mg/l	lb/d			1

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (as N)			<0.4	<273.8					1	mg/l	lb/d			1
h. Oil and Grease			<5.5	<3765.0					1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<136.9					1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (as SO_4) (14808-79-8)			45	30804.6					1	mg/l	lb/d			1
l. Sulfide (as S)			290	198519					1	mg/l	lb/d			1
m. Sulfite (as SO_3) (14265-45-3)			2.56	1752.4					1	mg/l	lb/d			1
n. Surfactants			<0.05	<34.2					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			1.36	931.0					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.166	113.63					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			1.15	787.2					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<27.4					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			<0.04	<27.4					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			13.7	9378.3					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<27.4					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			<0.04	<27.4					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<13.7					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			<0.01	<6.8					1	mg/l	lb/d			1

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EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
GAD000612796 (Scherer)	07

CONTINUED FROM PAGE 3 OF FORM 2-C

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<3.4					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<3.4					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.68					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.48					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<3.4					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				<0.005	<3.4					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.68					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.00367	2.51					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				<0.005	<3.4					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				0.0077	5.27					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<3.4					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.68					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				<0.01	<6.8					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<13.7					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<34.2					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<34.2					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<34.2					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<1.4					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<6.8					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<1.4					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<6.8					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<6.8					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<3.4					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<6.8					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				<0.002	<1.4					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<6.8					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<6.8					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<1.4					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<1.4					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<1.4					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<1.4					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<1.4					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<1.4					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<6.8					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<6.8					1	mg/l	lb/day			1

* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<6.8					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<1.4					1	mg/l	lb/day			1
24V. Tetrachloroethylene (127-18-4)				<0.002	<1.4					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<1.4					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<1.4					1	mg/l	lb/day			1
27V. 1,1,1-Trichloroethane (71-55-6)				<0.002	<1.4					1	mg/l	lb/day			1
28V. 1,1,2-Trichloroethane (79-00-5)				<0.002	<1.4					1	mg/l	lb/day			1
29V Trichloroethylene (79-01-6)				<0.002	<1.4					1	mg/l	lb/day			1
30V. Trichlorofluoromethane (75-69-4)				<0.01	<6.8					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<6.8					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<6.8					1	mg/l	lb/day			1
2A. 2,4-Dichlorophenol (120-83-2)				<0.01	<6.8					1	mg/l	lb/day			1
3A. 2,4-Dimethylphenol (105-67-9)				<0.01	<6.8					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<34.2					1	mg/l	lb/day			1
5A. 2,4-Dinitrophenol (51-28-5)				<0.05	<34.2					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<34.2					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<34.2					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<6.8					1	mg/l	lb/day			1
9A. Pentachlorophenol (87-86-5)				<0.02	<13.7					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<6.8					1	mg/l	lb/day			1
11A. 2,4,6-Trichlorophenol (88-05-2)				<0.01	<6.8					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<6.8					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<6.8					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<6.8					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<54.8					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<6.8					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<6.8					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<6.8					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<6.8					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<6.8					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<6.8					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<6.8					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<6.8					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<6.8					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<6.8					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<6.8					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<6.8					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<6.8					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<6.8					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<6.8					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<6.8					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<6.8					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<6.8					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<13.7					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<6.8					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131-11-3)				<0.01	<6.8					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<6.8					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<13.7					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<13.7					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<6.8					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<6.8					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<6.8					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<6.8					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<6.8					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<6.8					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<6.8					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<6.8					1	mg/l	lb/day			1
37B. Indeno (1,2,3-cd) Pyrene (193-39-5)				<0.01	<6.8					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<6.8					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<6.8					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<6.8					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<6.8					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<6.8					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitrosodiphenylamine (86-30-6)				<0.01	<6.8					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<6.8					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<6.8					1	mg/l	lb/day			1
46B. 1,2,4-Trichlorobenzene (120-82-1)				<0.01	<6.8					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.68					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.68					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.68					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.68					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.68					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.68					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.68					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

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PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages.
SEE INSTRUCTIONS.

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V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO.
08

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT						d. NO. OF ANALYSES	3. UNITS (*specify if blank*)		4. INTAKE (*optional*)		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)			a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand (*BOD*)	<4.0	<16					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	17	66.4					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	3.4	13.3					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	5	19.5					1	mg/l	lb/d			1
e. Ammonia (*as N*)	0.24	0.94					1	mg/l	lb/d			1
f. Flow	VALUE 325		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 18.31		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 29.61		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 8.57	MAXIMUM 8.57	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)			<1.0	<0.4					1	mg/l	lb/d			1
b. Chlorine, Total Residual			0.1						1	mg/l				1
c. Color			60						1	PCU				1
d. Fecal Coliform			5000				180		4	col/100				1
e. Fluoride (16984-48-8)			0.24	0.94					1	mg/l	lb/d			1
f. Nitrate-Nitrite (*as N*)			<0.10	<0.4					1	mg/l	lb/d			1

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (*as N*)			<0.40	<1.6					1	mg/l	lb/d			1
h. Oil and Grease			<5.5	<22.5					1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<0.8					1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (*as SO_4*) (14808-79-8)			23	89.8					1	mg/l	lb/d			1
l. Sulfide (*as S*)			<0.2	<0.8					1	mg/l	lb/d			1
m. Sulfite (*as SO_3*) (14265-45-3)			1.28	5					1	mg/l	lb/d			1
n. Surfactants			<0.05	<0.2					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			0.139	0.54					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.033	0.13					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			<0.04	<1.6					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<1.6					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.187	0.73					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			2.0	7.8					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<1.6					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			0.546	2.13					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<0.08					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			<0.01	<0.04					1	mg/l	lb/d			1

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GAD000612796 (Scherer)	08

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PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<0.02					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<0.02					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.004					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.003					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<0.02					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				<0.005	<0.02					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.004					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.00178	0.007					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				<0.005	<0.02					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<0.02					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<0.02					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.004					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				0.0115	0.045					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<0.08					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<0.2					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<0.2					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<0.2					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<0.008					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<0.04					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.008					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<0.04					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<0.04					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<0.02					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<0.04					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				<0.002	<0.008					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<0.04					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<0.04					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<0.008					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<0.008					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<0.008					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<0.008					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<0.008					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<0.008					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<0.04					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<0.04					1	mg/l	lb/day			1

CONTINUE ON PAGE V-5

* Analytical Method Unavailable

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<0.04					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.008					1	mg/l	lb/day			1
24V. Tetrachloro-ethylene (127-18-4)				<0.002	<0.008					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<0.008					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.008					1	mg/l	lb/day			1
27V. 1,1,1-Trichloro-ethane (71-55-6)				<0.002	<0.008					1	mg/l	lb/day			1
28V. 1,1,2-Trichloro-ethane (79-00-5)				<0.002	<0.008					1	mg/l	lb/day			1
29V Trichloro-ethylene (79-01-6)				<0.002	<0.008					1	mg/l	lb/day			1
30V. Trichloro-fluoromethane (75-69-4)				<0.01	<0.04					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<0.04					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<0.04					1	mg/l	lb/day			1
2A. 2,4-Dichloro-phenol (120-83-2)				<0.01	<0.04					1	mg/l	lb/day			1
3A. 2,4-Dimethyl-phenol (105-67-9)				<0.01	<0.04					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<0.2					1	mg/l	lb/day			1
5A. 2,4-Dinitro-phenol (51-28-5)				<0.05	<0.2					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<0.2					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<0.2					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<0.04					1	mg/l	lb/day			1
9A. Pentachloro-phenol (87-86-5)				<0.02	<0.08					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<0.04					1	mg/l	lb/day			1
11A. 2,4,6-Trichloro-phenol (88-05-2)				<0.01	<0.04					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<0.04					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<0.04					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<0.04					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<0.32					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<0.04					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<0.04					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<0.04					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<0.04					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<0.04					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<0.04					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<0.04					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<0.04					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<0.04					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<0.04					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<0.04					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<0.04					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<0.04					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<0.04					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<0.04					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<0.04					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<0.04					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichloro-benzene (106-46-7)				<0.01	<0.04					1	mg/l	lb/day			1
23B. 3,3-Dichloro-benzidine (91-94-1)				<0.02	<0.08					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<0.04					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131 -11-3)				<0.01	<0.04					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<0.04					1	mg/l	lb/day			1
27B. 2,4-Dinitro-toluene (121-14-2)				<0.02	<0.08					1	mg/l	lb/day			1
28B. 2,6-Dinitro-toluene (606-20-2)				<0.02	<0.08					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<0.04					1	mg/l	lb/day			1
30B. 1,2-Diphenyl-hydrazine (*as Azo-benzene*) (122-66-7)				<0.01	<0.04					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<0.04					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<0.04					1	mg/l	lb/day			1
33B. Hexachloro-benzene (118-74-1)				<0.01	<0.04					1	mg/l	lb/day			1
34B. Hexachloro-butadiene (87-68-3)				<0.01	<0.04					1	mg/l	lb/day			1
35B. Hexachloro-cyclopentadiene (77-47-4)				<0.01	<0.04					1	mg/l	lb/day			1
36B Hexachloro-ethane (67-72-1)				<0.01	<0.04					1	mg/l	lb/day			1
37B. Indeno (1,2,3-cd) Pyrene (193-39-5)				<0.01	<0.04					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<0.04					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<0.04					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<0.04					1	mg/l	lb/day			1
41B. N-Nitro-sodimethylamine (62-75-9)				<0.01	<0.04					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<0.04					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitrosodiphenylamine (86-30-6)				<0.01	<0.04					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<0.04					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<0.04					1	mg/l	lb/day			1
46B. 1,2,4-Trichlorobenzene (120-82-1)				<0.01	<0.04					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.004					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.004					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.004					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.004					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.004					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.004					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.004					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages. SEE INSTRUCTIONS.

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V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 09

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT							3. UNITS (*specify if blank*)		4. INTAKE (*optional*)		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand (*BOD*)	<8.0	<7.5					1	mg/l	lb/d	<8.0		1
b. Chemical Oxygen Demand (*COD*)	<10	<9.37					1	mg/l	lb/d	<10		1
c. Total Organic Carbon (*TOC*)	4.6	4.3					1	mg/l	lb/d	4.6		1
d. Total Suspended Solids (*TSS*)	<5	<4.7					1	mg/l	lb/d	<5		1
e. Ammonia (*as N*)	0.12	0.11					1	mg/l	lb/d	0.12		1
f. Flow	VALUE 78		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 17.49		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 29.05		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 8.91	MAXIMUM 8.91	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)			<1.0	<0.94					1	mg/l	lb/d	<1.0		1
b. Chlorine, Total Residual			<0.1						1	mg/l		<0.1		1
c. Color			30						1	PCU		30		1
d. Fecal Coliform			14						1	col/100		14		1
e. Fluoride (16984-48-8)			0.26	0,24					1	mg/l	lb/d	0.26		1
f. Nitrate-Nitrite (as N)			<0.10	<0.094					1	mg/l	lb/d	<0.10		1

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (as N)			<0.40	<0.38					1	mg/l	lb/d	<0.40		1
h. Oil and Grease			<5.8	<5.4					1	mg/l	lb/d	<5.8		1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<0.19					1	mg/l	lb/d	<0.2		1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (as SO_4) (14808-79-8)			23	21.5					1	mg/l	lb/d			1
l. Sulfide (as S)			<0.2	<0.19					1	mg/l	lb/d			1
m. Sulfite (as SO_3) (14265-45-3)			0.64	0.6					1	mg/l	lb/d			1
n. Surfactants			0.08	0.07					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			<0.1	<0.094					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.0209	0.0196					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			<0.04	<0.038					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<0.038					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.0625	0.059					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			2.0	1.9					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<0.038					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			<0.04	<0.038					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<0.019					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			<0.01	<0.009					1	mg/l	lb/d			1

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PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<0.005					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<0.005					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.001					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<.0007					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<0.005					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				<0.005	<0.005					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.001					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.000736	0.0007					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				<0.005	<0.005					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<0.005					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<0.005					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.001					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				<0.01	<0.009					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<0.02					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<0.047					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetrachlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<0.047					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<0.047					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<0.002					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<0.009					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.002					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<0.009					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<0.009					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<0.005					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<0.009					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				<0.002	<0.002					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<0.009					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<0.009					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<0.002					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<0.002					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<0.002					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<0.002					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<0.002					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<0.002					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<0.009					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<0.009					1	mg/l	lb/day			1

* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<0.009					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.002					1	mg/l	lb/day			1
24V. Tetrachloro-ethylene (127-18-4)				<0.002	<0.002					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<0.002					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.002					1	mg/l	lb/day			1
27V. 1,1,1-Trichloro-ethane (71-55-6)				<0.002	<0.002					1	mg/l	lb/day			1
28V. 1,1,2-Trichloro-ethane (79-00-5)				<0.002	<0.002					1	mg/l	lb/day			1
29V Trichloro-ethylene (79-01-6)				<0.002	<0.002					1	mg/l	lb/day			1
30V. Trichloro-fluoromethane (75-69-4)				<0.01	<0.009					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<0.009					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<0.009					1	mg/l	lb/day			1
2A. 2,4-Dichloro-phenol (120-83-2)				<0.01	<0.009					1	mg/l	lb/day			1
3A. 2,4-Dimethyl-phenol (105-67-9)				<0.01	<0.009					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<0.047					1	mg/l	lb/day			1
5A. 2,4-Dinitro-phenol (51-28-5)				<0.05	<0.047					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<0.047					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<0.047					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<0.009					1	mg/l	lb/day			1
9A. Pentachloro-phenol (87-86-5)				<0.02	<0.019					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<0.009					1	mg/l	lb/day			1
11A. 2,4,6-Trichloro-phenol (88-05-2)				<0.01	<0.009					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<0.009					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<0.009					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<0.009					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<0.075					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<0.009					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<0.009					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<0.009					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<0.009					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<0.009					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<0.009					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<0.009					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<0.009					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<0.009					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<0.009					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<0.009					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<0.009					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<0.009					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<0.009					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<0.009					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<0.009					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<0.009					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<0.009					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<0.019					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<0.009					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131-11-3)				<0.01	<0.009					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<0.009					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<0.019					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<0.019					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<0.009					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<0.009					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<0.009					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<0.009					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<0.009					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<0.009					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<0.009					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<0.009					1	mg/l	lb/day			1
37B. Indeno (*1,2,3-cd*) Pyrene (193-39-5)				<0.01	<0.009					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<0.009					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<0.009					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<0.009					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<0.009					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<0.009					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitrosodiphenylamine (86-30-6)				<0.01	<0.009					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<0.009					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<0.009					1	mg/l	lb/day			1
46B. 1,2,4-Trichlorobenzene (120-82-1)				<0.01	<0.009					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
GAD000612796 (Scherer)	09

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.001					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.001					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.001					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.001					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.001					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.001					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.001					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

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PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages.
SEE INSTRUCTIONS.

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GAD000612796 (Scherer)

V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO.
10

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT						d. NO. OF ANALYSES	3. UNITS (*specify if blank*)		4. INTAKE (*optional*)		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)			a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand (*BOD*)	<8.0	<73.5					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	<10	<92					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	4.6	42.3					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	<5	<46					1	mg/l	lb/d			1
e. Ammonia (*as N*)	0.12	1.1					1	mg/l	lb/d			1
f. Flow	VALUE 765		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 17.49		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 29.05		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 8.91	MAXIMUM 8.91	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)			<1.0	<9.2					1	mg/l	lb/d			1
b. Chlorine, Total Residual			<0.1						1	mg/l				1
c. Color			30						1	PCU				1
d. Fecal Coliform			14						1	col/100				1
e. Fluoride (16984-48-8)			0.26	2.4					1	mg/l	lb/d			1
f. Nitrate-Nitrite (as *N*)			<0.10	<0.92					1	mg/l	lb/d			1

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (as N)			<0.40	<3.7					1	mg/l	lb/d			1
h. Oil and Grease			<5.8	<53.3					1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<1.84					1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (as SO_4) (14808-79-8)			23	211					1	mg/l	lb/d			1
l. Sulfide (as S)			<0.2	<1.84					1	mg/l	lb/d			1
m. Sulfite (as SO_3) (14265-45-3)			0.64	5.9					1	mg/l	lb/d			1
n. Surfactants			0.08	0.73					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			<0.1	<0.92					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.0209	0.19					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			<0.04	<3.7					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<3.7					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.0625	0.57					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			2.0	18.4					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<3.7					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			<0.04	<3.7					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<1.84					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			<0.01	<0.09					1	mg/l	lb/d			1

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PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<0.046					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<0.046					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.009					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.007					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<0.046					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				<0.005	<0.046					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.009					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.000736	0.0068					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				<0.005	<0.046					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<0.046					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<0.046					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.009					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				<0.01	<0.09					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<0.184					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<0.46					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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1. POLLUTANT AND CAS NUMBER (if available)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (if available)		c. LONG TERM AVRG. VALUE (if available)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<0.46					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<0.46					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<0.02					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<0.09					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.02					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<0.09					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<0.09					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<0.046					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<0.09					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				<0.002	<0.02					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<0.09					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<0.09					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<0.02					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<0.02					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<0.02					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<0.02					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<0.02					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<0.02					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<0.09					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<0.09					1	mg/l	lb/day			1

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* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<0.09					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.02					1	mg/l	lb/day			1
24V. Tetrachloroethylene (127-18-4)				<0.002	<0.02					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<0.02					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.02					1	mg/l	lb/day			1
27V. 1,1,1-Trichloroethane (71-55-6)				<0.002	<0.02					1	mg/l	lb/day			1
28V. 1,1,2-Trichloroethane (79-00-5)				<0.002	<0.02					1	mg/l	lb/day			1
29V Trichloroethylene (79-01-6)				<0.002	<0.02					1	mg/l	lb/day			1
30V. Trichlorofluoromethane (75-69-4)				<0.01	<0.09					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<0.09					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<0.09					1	mg/l	lb/day			1
2A. 2,4-Dichlorophenol (120-83-2)				<0.01	<0.09					1	mg/l	lb/day			1
3A. 2,4-Dimethylphenol (105-67-9)				<0.01	<0.09					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<0.46					1	mg/l	lb/day			1
5A. 2,4-Dinitrophenol (51-28-5)				<0.05	<0.46					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<0.46					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<0.46					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<0.09					1	mg/l	lb/day			1
9A. Pentachlorophenol (87-86-5)				<0.02	<0.184					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<0.09					1	mg/l	lb/day			1
11A. 2,4,6-Trichlorophenol (88-05-2)				<0.01	<0.09					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<0.09					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<0.09					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<0.09					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<0.74					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<0.09					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<0.09					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<0.09					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<0.09					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<0.09					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<0.09					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<0.09					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<0.09					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<0.09					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<0.09					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<0.09					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<0.09					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<0.09					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<0.09					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<0.09					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<0.09					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<0.09					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<0.09					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<0.184					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<0.09					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131-11-3)				<0.01	<0.09					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<0.09					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<0.184					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<0.184					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<0.09					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<0.09					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<0.09					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<0.09					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<0.09					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<0.09					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<0.09					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<0.09					1	mg/l	lb/day			1
37B. Indeno (*1,2,3-cd*) Pyrene (193-39-5)				<0.01	<0.09					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<0.09					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<0.09					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<0.09					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<0.09					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<0.09					1	mg/l	lb/day			1

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitro-sodiphenylamine (86-30-6)				<0.01	<0.09					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<0.09					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<0.09					1	mg/l	lb/day			1
46B. 1,2,4-Tri-chlorobenzene (120-82-1)				<0.01	<0.09					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.009					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.009					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.009					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.009					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.009					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.009					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.009					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

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PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages. SEE INSTRUCTIONS.

EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796 (Scherer)

V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO.: 11

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	3. UNITS (*specify if blank*) a. CONCEN-TRATION	3. UNITS b. MASS	4. INTAKE (*optional*) a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	4. INTAKE a. LONG TERM AVERAGE VALUE (2) MASS	4. INTAKE b. NO. OF ANALYSES
a. Biochemical Oxygen Demand (*BOD*)	<8	<10					1	mg/l	lb/d	<8		1
b. Chemical Oxygen Demand (*COD*)	<10	<12					1	mg/l	lb/d	<10		1
c. Total Organic Carbon (*TOC*)	4.8	5.8					1	mg/l	lb/d	4.8		1
d. Total Suspended Solids (*TSS*)	<5	<6					1	mg/l	lb/d	<5		1
e. Ammonia (*as N*)	<0.10	<0.12					1	mg/l	lb/d	<0.10		1
f. Flow	VALUE 100		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 16.53		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 25.09		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 7.54	MAXIMUM 7.54	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X" a. BELIEVED PRESENT	2. MARK "X" b. BELIEVED ABSENT	3. EFFLUENT a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	4. UNITS a. CONCEN-TRATION	4. UNITS b. MASS	5. INTAKE (*optional*) a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	5. INTAKE a. LONG TERM AVERAGE VALUE (2) MASS	5. INTAKE b. NO. OF ANALYSES
a. Bromide (24959-67-9)			<1.0	<1.2					1	mg/l	lb/d	<1.0		1
b. Chlorine, Total Residual			0.1						1	mg/l		0.1		1
c. Color			200						1	PCU		200		1
d. Fecal Coliform			800						1	col/100		800		1
e. Fluoride (16984-48-8)			0.31	0.37					1	mg/l	lb/d	0.31		1
f. Nitrate-Nitrite (*as N*)			0.89	1.07					1	mg/l	lb/d	0.89		1

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (*as N*)			<0.40	<0.48					1	mg/l	lb/d	<0.40		1
h. Oil and Grease			<5.4	<6.5					1	mg/l	lb/d	<5.4		1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<0.24					1	mg/l	lb/d	<0.2		1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (*as SO_4*) (14808-79-8)			22	26					1	mg/l	lb/d			1
l. Sulfide (*as S*)			<0.2	<0.24					1	mg/l	lb/d			1
m. Sulfite (*as SO_3*) (14265-45-3)			1.92	2.3					1	mg/l	lb/d			1
n. Surfactants			0.06	0.07					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			0.409	0.49					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.0239	0.029					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			<0.04	<0.05					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<0.05					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.76	0.9					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			1.45	1.74					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<0.05					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			0.0792	<0.095					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<0.24					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			0.0147	0.018					1	mg/l	lb/d			1

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GAD000612796 (Scherer)	11

CONTINUED FROM PAGE 3 OF FORM 2-C

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<0.006					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<0.006					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<.0012					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<.0008					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<0.006					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				<0.005	<0.006					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<.0012					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.000995	0.0012					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				0.0465	0.056					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<0.006					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<0.006					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<.0012					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				<0.01	<0.012					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<0.024					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<0.06					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<0.06					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<0.06					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<.0024					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<0.012					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<.0024					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<0.012					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<0.012					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<0.006					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<0.012					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				<0.002	<.0024					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<0.012					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<0.012					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<.0024					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<.0024					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<.0024					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<.0024					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<.0024					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<.0024					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<0.012					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<0.012					1	mg/l	lb/day			1

* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<0.012					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<.0024					1	mg/l	lb/day			1
24V. Tetrachloro-ethylene (127-18-4)				<0.002	<.0024					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<.0024					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<.0024					1	mg/l	lb/day			1
27V. 1,1,1-Trichloro-ethane (71-55-6)				<0.002	<.0024					1	mg/l	lb/day			1
28V. 1,1,2-Trichloro-ethane (79-00-5)				<0.002	<.0024					1	mg/l	lb/day			1
29V Trichloro-ethylene (79-01-6)				<0.002	<.0024					1	mg/l	lb/day			1
30V. Trichloro-fluoromethane (75-69-4)				<0.01	<0.012					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<0.012					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<0.012					1	mg/l	lb/day			1
2A. 2,4-Dichloro-phenol (120-83-2)				<0.01	<0.012					1	mg/l	lb/day			1
3A. 2,4-Dimethyl-phenol (105-67-9)				<0.01	<0.012					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<0.06					1	mg/l	lb/day			1
5A. 2,4-Dinitro-phenol (51-28-5)				<0.05	<0.06					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<0.06					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<0.06					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<0.012					1	mg/l	lb/day			1
9A. Pentachloro-phenol (87-86-5)				<0.02	<0.024					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<0.012					1	mg/l	lb/day			1
11A. 2,4,6-Trichloro-phenol (88-05-2)				<0.01	<0.012					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<0.012					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<0.012					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<0.012					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<0.096					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<0.012					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<0.012					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<0.012					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<0.012					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<0.012					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<0.012					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<0.012					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<0.012					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<0.012					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<0.012					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<0.012					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<0.012					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<0.012					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<0.012					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<0.012					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<0.012					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<0.012					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<0.012					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<0.024					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<0.012					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131 -11-3)				<0.01	<0.012					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<0.012					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<0.024					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<0.024					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<0.012					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<0.012					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<0.012					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<0.012					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<0.012					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<0.012					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<0.012					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<0.012					1	mg/l	lb/day			1
37B. Indeno (1,2,3-*cd*) Pyrene (193-39-5)				<0.01	<0.012					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<0.012					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<0.012					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<0.012					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<0.012					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<0.012					1	mg/l	lb/day			1

CONTINUE ON REVERSE

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitro-sodiphenylamine (86-30-6)				<0.01	<0.012					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<0.012					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<0.012					1	mg/l	lb/day			1
46B. 1,2,4-Tri-chlorobenzene (120-82-1)				<0.01	<0.012					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<.0012					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<.0012					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<.0012					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<.0012					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<.0012					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<.0012					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<.0012					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages.
SEE INSTRUCTIONS.

EPA I.D. NUMBER (*copy from Item 1 of Form 1*)
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V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 12

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT						3. UNITS (*specify if blank*)		4. INTAKE (*optional*)		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand (*BOD*)	<8	<244					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	<10	<305					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	<1	<31					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	<5	<153					1	mg/l	lb/d			1
e. Ammonia (*as N*)	0.17	5.2					1	mg/l	lb/d			1
f. Flow	VALUE 2536		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 14.85		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 26.92		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 8.34	MAXIMUM 8.34	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)			<1.0	<31					1	mg/l	lb/d			1
b. Chlorine, Total Residual			<0.1						1	mg/l				1
c. Color			<5						1	PCU				1
d. Fecal Coliform			10						1	col/100				1
e. Fluoride (16984-48-8)			<0.10	<3.1					1	mg/l	lb/d			1
f. Nitrate-Nitrite (*as N*)			<0.10	<3.1					1	mg/l	lb/d			1

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (*as N*)			<0.40	<12.2					1	mg/l	lb/d			1
h. Oil and Grease			<5.4	<164.5					1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<6.1					1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (*as SO_4*) (14808-79-8)			29	883					1	mg/l	lb/d			1
l. Sulfide (*as S*)			<0.2	<6.1					1	mg/l	lb/d			1
m. Sulfite (*as SO_3*) (14265-45-3)			1.92	58.5					1	mg/l	lb/d			1
n. Surfactants			<0.05	<1.6					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			<0.1	<3.1					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			<0.005	<0.153					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			<0.04	<1.22					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<1.22					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			<0.04	<1.22					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			<0.05	<1.53					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<1.22					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			<0.04	<1.22					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<6.1					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			<0.01	<0.31					1	mg/l	lb/d			1

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PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE (1) CONCENTRATION	a. MAXIMUM DAILY VALUE (2) MASS	b. MAXIMUM 30 DAY VALUE (*if available*) (1) CONCENTRATION	b. MAXIMUM 30 DAY VALUE (*if available*) (2) MASS	c. LONG TERM AVRG. VALUE (*if available*) (1) CONCENTRATION	c. LONG TERM AVRG. VALUE (*if available*) (2) MASS	d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE (1) CONCENTRATION	a. LONG TERM AVERAGE VALUE (2) MASS	b. NO. OF ANALYSES
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<0.153					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<0.153					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.031					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.014					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<0.153					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				<0.005	<0.153					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.031					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				<0.0005	<0.016					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				<0.005	<0.153					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<0.153					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<0.153					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.031					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				<0.01	<0.31					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<0.61					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<1.53					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<1.53					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<1.53					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<0.061					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<0.31					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.061					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<0.31					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<0.31					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<0.153					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<0.31					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				0.0073	0.22					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<0.31					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<0.31					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<0.061					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<0.061					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<0.061					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<0.061					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<0.061					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<0.061					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<0.31					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<0.31					1	mg/l	lb/day			1

* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<0.31					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.061					1	mg/l	lb/day			1
24V. Tetrachloro-ethylene (127-18-4)				<0.002	<0.061					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<0.061					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.061					1	mg/l	lb/day			1
27V. 1,1,1-Trichloro-ethane (71-55-6)				<0.002	<0.061					1	mg/l	lb/day			1
28V. 1,1,2-Trichloro-ethane (79-00-5)				<0.002	<0.061					1	mg/l	lb/day			1
29V Trichloro-ethylene (79-01-6)				<0.002	<0.061					1	mg/l	lb/day			1
30V. Trichloro-fluoromethane (75-69-4)				<0.01	<0.31					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<0.31					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<0.31					1	mg/l	lb/day			1
2A. 2,4-Dichloro-phenol (120-83-2)				<0.01	<0.31					1	mg/l	lb/day			1
3A. 2,4-Dimethyl-phenol (105-67-9)				<0.01	<0.31					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<1.53					1	mg/l	lb/day			1
5A. 2,4-Dinitro-phenol (51-28-5)				<0.05	<1.53					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<1.53					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<1.53					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<0.31					1	mg/l	lb/day			1
9A. Pentachloro-phenol (87-86-5)				<0.02	<0.61					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<0.31					1	mg/l	lb/day			1
11A. 2,4,6-Trichloro-phenol (88-05-2)				<0.01	<0.31					1	mg/l	lb/day			1

CONTINUE ON REVERSE

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<0.31					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<0.31					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<0.31					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<2.44					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<0.31					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<0.31					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<0.31					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<0.31					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<0.31					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<0.31					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<0.31					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<0.31					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<0.31					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<0.31					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<0.31					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<0.31					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<0.31					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<0.31					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<0.31					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<0.31					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<0.31					1	mg/l	lb/day			1

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichloro-benzene (106-46-7)				<0.01	<0.31					1	mg/l	lb/day			1
23B. 3,3-Dichloro-benzidine (91-94-1)				<0.02	<0.61					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<0.31					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131 -11-3)				<0.01	<0.31					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<0.31					1	mg/l	lb/day			1
27B. 2,4-Dinitro-toluene (121-14-2)				<0.02	<0.61					1	mg/l	lb/day			1
28B. 2,6-Dinitro-toluene (606-20-2)				<0.02	<0.61					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<0.31					1	mg/l	lb/day			1
30B. 1,2-Diphenyl-hydrazine (*as Azo-benzene*) (122-66-7)				<0.01	<0.31					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<0.31					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<0.31					1	mg/l	lb/day			1
33B. Hexachloro-benzene (118-74-1)				<0.01	<0.31					1	mg/l	lb/day			1
34B. Hexachloro-butadiene (87-68-3)				<0.01	<0.31					1	mg/l	lb/day			1
35B. Hexachloro-cyclopentadiene (77-47-4)				<0.01	<0.31					1	mg/l	lb/day			1
36B Hexachloro-ethane (67-72-1)				<0.01	<0.31					1	mg/l	lb/day			1
37B. Indeno (*1,2,3-cd*) Pyrene (193-39-5)				<0.01	<0.31					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<0.31					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<0.31					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<0.31					1	mg/l	lb/day			1
41B. N-Nitro-sodimethylamine (62-75-9)				<0.01	<0.31					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<0.31					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitrosodiphenylamine (86-30-6)				<0.01	<0.31					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<0.31					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<0.31					1	mg/l	lb/day			1
46B. 1,2,4-Trichlorobenzene (120-82-1)				<0.01	<0.31					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.031					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.031					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.031					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.031					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.031					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.031					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.031					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

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PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages. SEE INSTRUCTIONS.

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V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 13

PART A – You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT							3. UNITS (*specify if blank*)		4. INTAKE (*optional*)		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand (*BOD*)	<4	<207					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	<10	<517					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	4.0	206.6					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	26	1342.7					1	mg/l	lb/d			1
e. Ammonia (*as N*)	0.23	11.9					1	mg/l	lb/d			1
f. Flow	VALUE 4,300		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 21.49		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 31.65		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 10.2	MAXIMUM 10.2	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)			<1.0	<52					1	mg/l	lb/d			1
b. Chlorine, Total Residual			<0.1						1	mg/l				1
c. Color			90						1	PCU				1
d. Fecal Coliform			<4.0						1	col/100				1
e. Fluoride (16984-48-8)			<4	<207					1	mg/l	lb/d			1
f. Nitrate-Nitrite (*as N*)			0.62	32					1	mg/l	lb/d			1

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (as *N*)			<0.40		<21				1	mg/l	lb/d			1
h. Oil and Grease			<6		<310				1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2		<10.4				1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (as SO_4) (14808-79-8)			210	10844.7					1	mg/l	lb/d			1
l. Sulfide (as *S*)			<0.2	<10.4					1	mg/l	lb/d			1
m. Sulfite (as SO_3) (14265-45-3)			3.2	165.3					1	mg/l	lb/d			1
n. Surfactants			0.35	18.1					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			3.45	178.2					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.114	5.9					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			0.317	16.4					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<2.1					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.314	16.2					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			2.69	138.9					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<2.1					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			0.0577	3					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<10.4					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			0.0311	1.6					1	mg/l	lb/d			1

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PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<0.26					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<0.26					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.052					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.04					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<0.26					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				<0.005	<0.26					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.052					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.00219	0.113					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				<0.005	<0.26					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<0.26					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<0.26					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.052					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				0.0233	1.2					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<1.033					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<2.59					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<2.59					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<2.59					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<0.11					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<0.52					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.11					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<0.52					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<0.52					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<0.26					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<0.52					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				0.0046	0.24					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<0.52					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<0.52					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<0.11					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<0.11					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<0.11					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<0.11					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<0.11					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<0.11					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<0.52					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<0.52					1	mg/l	lb/day			1

* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<0.52					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.11					1	mg/l	lb/day			1
24V. Tetrachloroethylene (127-18-4)				<0.002	<0.11					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<0.11					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.11					1	mg/l	lb/day			1
27V. 1,1,1-Trichloroethane (71-55-6)				<0.002	<0.11					1	mg/l	lb/day			1
28V. 1,1,2-Trichloroethane (79-00-5)				<0.002	<0.11					1	mg/l	lb/day			1
29V Trichloroethylene (79-01-6)				<0.002	<0.11					1	mg/l	lb/day			1
30V. Trichlorofluoromethane (75-69-4)				<0.01	<0.52					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<0.52					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<0.52					1	mg/l	lb/day			1
2A. 2,4-Dichlorophenol (120-83-2)				<0.01	<0.52					1	mg/l	lb/day			1
3A. 2,4-Dimethylphenol (105-67-9)				<0.01	<0.52					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<2.59					1	mg/l	lb/day			1
5A. 2,4-Dinitrophenol (51-28-5)				<0.05	<2.59					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<2.59					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<2.59					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<0.52					1	mg/l	lb/day			1
9A. Pentachlorophenol (87-86-5)				<0.02	<1.033					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<0.52					1	mg/l	lb/day			1
11A. 2,4,6-Trichlorophenol (88-05-2)				<0.01	<0.52					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<0.52					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<0.52					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<0.52					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<4.2					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<0.52					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<0.52					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<0.52					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<0.52					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<0.52					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<0.52					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<0.52					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<0.52					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<0.52					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<0.52					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<0.52					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<0.52					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<0.52					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<0.52					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<0.52					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<0.52					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<0.52					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<0.52					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<1.033					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<0.52					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131 -11-3)				<0.01	<0.52					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<0.52					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<1.033					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<1.033					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<0.52					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<0.52					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<0.52					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<0.52					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<0.52					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<0.52					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<0.52					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<0.52					1	mg/l	lb/day			1
37B. Indeno (*1,2,3-cd*) Pyrene (193-39-5)				<0.01	<0.52					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<0.52					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<0.52					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<0.52					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<0.52					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<0.52					1	mg/l	lb/day			1

CONTINUED FROM THE FRONT

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitrosodiphenylamine (86-30-6)				<0.01	<0.52					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<0.52					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<0.52					1	mg/l	lb/day			1
46B. 1,2,4-Trichlorobenzene (120-82-1)				<0.01	<0.52					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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EPA I.D. NUMBER (*copy from Item 1 of Form 1*)	OUTFALL NUMBER
GAD000612796 (Scherer)	13

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.052					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.052					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.052					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.052					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.052					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.052					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.052					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

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PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (*use the same format*) instead of completing these pages.
SEE INSTRUCTIONS.

EPA I.D. NUMBER (*copy from Item 1 of Form 1*): GAD000612796 (Scherer)

V. INTAKE AND EFFLUENT CHARACTERISTICS *(continued from page 3 of Form 2-C)*

OUTFALL NO. 14

PART A –You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT							3. UNITS (*specify if blank*)		4. INTAKE (*optional*)		
	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Biochemical Oxygen Demand (*BOD*)	<9	<465					1	mg/l	lb/d			1
b. Chemical Oxygen Demand (*COD*)	82	4235					1	mg/l	lb/d			1
c. Total Organic Carbon (*TOC*)	5.7	294.4					1	mg/l	lb/d			1
d. Total Suspended Solids (*TSS*)	27	1394.3					1	mg/l	lb/d			1
e. Ammonia (*as N*)	0.19	9.8					1	mg/l	lb/d			1
f. Flow	VALUE 4300		VALUE		VALUE		1	gpm		VALUE		1
g. Temperature (*winter*)	VALUE 21.49		VALUE		VALUE		1	°C		VALUE		1
h. Temperature (*summer*)	VALUE 32.75		VALUE		VALUE		1	°C		VALUE		1
i. pH	MINIMUM 9.72	MAXIMUM 9.72	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – Mark "X" in column 2-a for each pollutant you know or have reason to believe is present. Mark "X" in column 2-b for each pollutant you believe to be absent. If you mark column 2a for any pollutant which is limited either directly, or indirectly but expressly, in an effluent limitations guideline, you must provide the results of at least one analysis for that pollutant. For other pollutants for which you mark column 2a, you must provide quantitative data or an explanation of their presence in your discharge. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
a. Bromide (24959-67-9)			<1.0	<52					1	mg/l	lb/d			1
b. Chlorine, Total Residual			0.2						1	mg/l				1
c. Color			100						1	PCU				1
d. Fecal Coliform			<4.0						1	col/100				1
e. Fluoride (16984-48-8)			0.39	20.1					1	mg/l	lb/d			1
f. Nitrate-Nitrite (*as N*)			0.60	31					1	mg/l	lb/d			1

Scherer 2018 Outfall 14

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1. POLLUTANT AND CAS NO. (*if available*)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. BELIEVED PRESENT	b. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCEN-TRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
			(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
g. Nitrogen, Total Organic (*as N*)			<0.40	<21					1	mg/l	lb/d			1
h. Oil and Grease			<5.7	<294.4					1	mg/l	lb/d			1
i. Phosphorus (as P), Total (7723-14-0)			<0.2	<10.33					1	mg/l	lb/d			1
j. Radioactivity														
(1) Alpha, Total		X												
(2) Beta, Total		X												
(3) Radium, Total		X												
(4) Radium 226, Total		X												
k. Sulfate (*as SO_4*) (14808-79-8)			47	2427					1	mg/l	lb/d			1
l. Sulfide (*as S*)			<0.2	<10.33					1	mg/l	lb/d			1
m. Sulfite (*as SO_3*) (14265-45-3)			3.84	198.3					1	mg/l	lb/d			1
n. Surfactants			0.56	29					1	mg/l	lb/d			1
o. Aluminum, Total (7429-90-5)			0.759	39.2					1	mg/l	lb/d			1
p. Barium, Total (7440-39-3)			0.0989	5.1					1	mg/l	lb/d			1
q. Boron, Total (7440-42-8)			0.132	6.8					1	mg/l	lb/d			1
r. Cobalt, Total (7440-48-4)			<0.04	<2.1					1	mg/l	lb/d			1
s. Iron, Total (7439-89-6)			0.408	21.1					1	mg/l	lb/d			1
t. Magnesium, Total (7439-95-4)			3.54	182.8					1	mg/l	lb/d			1
u. Molybdenum, Total (7439-98-7)			<0.04	<2.1					1	mg/l	lb/d			1
v. Manganese, Total (7439-96-5)			0.142	7.3					1	mg/l	lb/d			1
w. Tin, Total (7440-31-5)			<0.02	<1.04					1	mg/l	lb/d			1
x. Titanium, Total (7440-32-6)			0.0317	1.64					1	mg/l	lb/d			1

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PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2c-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (*secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions*), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. If you mark column 2b for acrolein, acrylonitrile, 2,4 dinitrophenol, or 2-methyl-4, 6 dinitrophenol, you must provide the results of at least one analysis for each of these pollutants which you know or have reason to believe that you discharge in concentrations of 100 ppb or greater. Otherwise, for pollutants for which you mark column 2b, you must either submit at least one analysis or briefly describe the reasons the pollutant is expected to be discharged. Note that there are 7 pages to this part; please review each carefully. Complete one table (*all 7 pages*) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
METALS, CYANIDE, AND TOTAL PHENOLS															
1M. Antimony, Total (7440-36-0)				<0.005	<0.26					1	mg/l	lb/day			1
2M. Arsenic, Total (7440-38-2)				<0.005	<0.26					1	mg/l	lb/day			1
3M. Beryllium, Total (7440-41-7)				<0.001	<0.052					1	mg/l	lb/day			1
4M. Cadmium, Total (7440-43-9)				<0.0007	<0.036					1	mg/l	lb/day			1
5M. Chromium, Total (7440-47-3)				<0.005	<0.26					1	mg/l	lb/day			1
6M. Copper, Total (7440-50-8)				0.0682	3.52					1	mg/l	lb/day			1
7M. Lead, Total (7439-92-1)				<0.001	<0.052					1	mg/l	lb/day			1
8M. Mercury, Total (7439-97-6)				0.00219	0.113					1	ug/l	lb/day			1
9M. Nickel, Total (7440-02-0)				0.0063	0.33					1	mg/l	lb/day			1
10M. Selenium, Total (7782-49-2)				<0.005	<0.26					1	mg/l	lb/day			1
11M. Silver, Total (7440-22-4)				<0.005	<0.26					1	mg/l	lb/day			1
12M. Thallium, Total (7440-28-0)				<0.001	<0.052					1	mg/l	lb/day			1
13M. Zinc, Total (7440-66-6)				0.0112	0.58					1	mg/l	lb/day			1
14M. Cyanide, Total (57-12-5)				<0.02	<1.1					1	mg/l	lb/day			1
15M. Phenols, Total				<0.05	<2.6					1	mg/l	lb/day			1
DIOXIN															
2,3,7,8-Tetra-chlorodibenzo-P-Dioxin (1764-01-6)			X	DESCRIBE RESULTS											

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Accrolein (107-02-8)				<0.05	<2.6					1	mg/l	lb/day			1
2V. Acrylonitrile (107-13-1)				<0.05	<2.6					1	mg/l	lb/day			1
3V. Benzene (71-43-2)				<0.002	<0.11					1	mg/l	lb/day			1
4V. Bis (*Chloromethyl*) Ether (542-88-1)			X	*											
5V. Bromoform (75-25-2)				<0.01	<0.52					1	mg/l	lb/day			1
6V. Carbon Tetrachloride (56-23-5)				<0.002	<0.11					1	mg/l	lb/day			1
7V. Chlorobenzene (108-90-7)				<0.01	<0.52					1	mg/l	lb/day			1
8V. Chlorodibromomethane (124-48-1)				<0.01	<0.52					1	mg/l	lb/day			1
9V. Chloroethane (75-00-3)				<0.005	<0.26					1	mg/l	lb/day			1
10V. 2-Chloroethylvinyl Ether (110-75-8)				<0.01	<0.52					1	mg/l	lb/day			1
11V. Chloroform (67-66-3)				<0.002	<0.11					1	mg/l	lb/day			1
12V. Dichlorobromomethane (75-27-4)				<0.01	<0.52					1	mg/l	lb/day			1
13V. Dichlorodifluoromethane (75-71-8)				<0.01	<0.52					1	mg/l	lb/day			1
14V. 1,1-Dichloroethane (75-34-3)				<0.002	<0.11					1	mg/l	lb/day			1
15V. 1,2-Dichloroethane (107-06-2)				<0.002	<0.11					1	mg/l	lb/day			1
16V. 1,1-Dichloroethylene (75-35-4)				<0.002	<0.11					1	mg/l	lb/day			1
17V. 1,2-Dichloropropane (78-87-5)				<0.002	<0.11					1	mg/l	lb/day			1
18V. 1,3-Dichloropropylene (542-75-6)				<0.002	<0.11					1	mg/l	lb/day			1
19V. Ethylbenzene (100-41-4)				<0.002	<0.11					1	mg/l	lb/day			1
20V. Methyl Bromide (74-83-9)				<0.01	<0.52					1	mg/l	lb/day			1
21V. Methyl Chloride (74-87-3)				<0.01	<0.52					1	mg/l	lb/day			1

* Analytical Method Unavailable

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – VOLATILE COMPOUNDS (*continued*)															
22V. Methylene Chloride (75-09-2)				<0.01	<0.52					1	mg/l	lb/day			1
23V. 1,1,2,2-Tetrachloroethane (79-34-5)				<0.002	<0.11					1	mg/l	lb/day			1
24V. Tetrachloroethylene (127-18-4)				<0.002	<0.11					1	mg/l	lb/day			1
25V. Toluene (108-88-3)				<0.002	<0.11					1	mg/l	lb/day			1
26V. 1,2-Trans-Dichloroethylene (156-60-5)				<0.002	<0.11					1	mg/l	lb/day			1
27V. 1,1,1-Trichloroethane (71-55-6)				<0.002	<0.11					1	mg/l	lb/day			1
28V. 1,1,2-Trichloroethane (79-00-5)				<0.002	<0.11					1	mg/l	lb/day			1
29V Trichloroethylene (79-01-6)				<0.002	<0.11					1	mg/l	lb/day			1
30V. Trichlorofluoromethane (75-69-4)				<0.01	<0.52					1	mg/l	lb/day			1
31V. Vinyl Chloride (75-01-4)				<0.01	<0.52					1	mg/l	lb/day			1
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)				<0.01	<0.52					1	mg/l	lb/day			1
2A. 2,4-Dichlorophenol (120-83-2)				<0.01	<0.52					1	mg/l	lb/day			1
3A. 2,4-Dimethylphenol (105-67-9)				<0.01	<0.52					1	mg/l	lb/day			1
4A. 4,6-Dinitro-O-Cresol (534-52-1)				<0.05	<2.6					1	mg/l	lb/day			1
5A. 2,4-Dinitrophenol (51-28-5)				<0.05	<2.6					1	mg/l	lb/day			1
6A. 2-Nitrophenol (88-75-5)				<0.05	<2.6					1	mg/l	lb/day			1
7A. 4-Nitrophenol (100-02-7)				<0.05	<2.6					1	mg/l	lb/day			1
8A. P-Chloro-M-Cresol (59-50-7)				<0.01	<0.52					1	mg/l	lb/day			1
9A. Pentachlorophenol (87-86-5)				<0.02	<1.04					1	mg/l	lb/day			1
10A. Phenol (108-95-2)				<0.01	<0.52					1	mg/l	lb/day			1
11A. 2,4,6-Trichlorophenol (88-05-2)				<0.01	<0.52					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)				<0.01	<0.52					1	mg/l	lb/day			1
2B. Acenaphtylene (208-96-8)				<0.01	<0.52					1	mg/l	lb/day			1
3B. Anthracene (120-12-7)				<0.01	<0.52					1	mg/l	lb/day			1
4B. Benzidine (92-87-5)				<0.08	<4.14					1	mg/l	lb/day			1
5B. Benzo (*a*) Anthracene (56-55-3)				<0.01	<0.52					1	mg/l	lb/day			1
6B. Benzo (*a*) Pyrene (50-32-8)				<0.01	<0.52					1	mg/l	lb/day			1
7B. 3,4-Benzo-fluoranthene (205-99-2)				<0.01	<0.52					1	mg/l	lb/day			1
8B. Benzo (*ghi*) Perylene (191-24-2)				<0.01	<0.52					1	mg/l	lb/day			1
9B. Benzo (*k*) Fluoranthene (207-08-9)				<0.01	<0.52					1	mg/l	lb/day			1
10B. Bis (*2-Chloro-ethoxy*) Methane (111-91-1)				<0.01	<0.52					1	mg/l	lb/day			1
11B. Bis (*2-Chloro-ethyl*) Ether (111-44-4)				<0.01	<0.52					1	mg/l	lb/day			1
12B. Bis (*2-Chloroisopropyl*) Ether (102-80-1)				<0.01	<0.52					1	mg/l	lb/day			1
13B. Bis (*2-Ethyl-hexyl*) Phthalate (117-81-7)				<0.01	<0.52					1	mg/l	lb/day			1
14B. 4-Bromophenyl Phenyl Ether (101-55-3)				<0.01	<0.52					1	mg/l	lb/day			1
15B. Butyl Benzyl Phthalate (85-68-7)				<0.01	<0.52					1	mg/l	lb/day			1
16B. 2-Chloro-naphthalene (91-58-7)				<0.01	<0.52					1	mg/l	lb/day			1
17B. 4-Chloro-phenyl Phenyl Ether (7005-72-3)				<0.01	<0.52					1	mg/l	lb/day			1
18B. Chrysene (218-01-9)				<0.01	<0.52					1	mg/l	lb/day			1
19B. Dibenzo (*a,h*) Anthracene (53-70-3)				<0.01	<0.52					1	mg/l	lb/day			1
20B. 1,2-Dichloro-benzene (95-50-1)				<0.01	<0.52					1	mg/l	lb/day			1
21B. 1,3-Di-chloro-benzene (541-73-1)				<0.01	<0.52					1	mg/l	lb/day			1

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
22B. 1,4-Dichlorobenzene (106-46-7)				<0.01	<0.52					1	mg/l	lb/day			1
23B. 3,3-Dichlorobenzidine (91-94-1)				<0.02	<1.04					1	mg/l	lb/day			1
24B. Diethyl Phthalate (84-66-2)				<0.01	<0.52					1	mg/l	lb/day			1
25B. Dimethyl Phthalate (131-11-3)				<0.01	<0.52					1	mg/l	lb/day			1
26B. Di-N-Butyl Phthalate (84-74-2)				<0.01	<0.52					1	mg/l	lb/day			1
27B. 2,4-Dinitrotoluene (121-14-2)				<0.02	<1.04					1	mg/l	lb/day			1
28B. 2,6-Dinitrotoluene (606-20-2)				<0.02	<1.04					1	mg/l	lb/day			1
29B. Di-N-Octyl Phthalate (117-84-0)				<0.01	<0.52					1	mg/l	lb/day			1
30B. 1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)				<0.01	<0.52					1	mg/l	lb/day			1
31B. Fluoranthene (206-44-0)				<0.01	<0.52					1	mg/l	lb/day			1
32B. Fluorene (86-73-7)				<0.01	<0.52					1	mg/l	lb/day			1
33B. Hexachlorobenzene (118-74-1)				<0.01	<0.52					1	mg/l	lb/day			1
34B. Hexachlorobutadiene (87-68-3)				<0.01	<0.52					1	mg/l	lb/day			1
35B. Hexachlorocyclopentadiene (77-47-4)				<0.01	<0.52					1	mg/l	lb/day			1
36B Hexachloroethane (67-72-1)				<0.01	<0.52					1	mg/l	lb/day			1
37B. Indeno (*1,2,3-cd*) Pyrene (193-39-5)				<0.01	<0.52					1	mg/l	lb/day			1
38B. Isophorone (78-59-1)				<0.01	<0.52					1	mg/l	lb/day			1
39B. Naphthalene (91-20-3)				<0.01	<0.52					1	mg/l	lb/day			1
40B. Nitrobenzene (98-95-3)				<0.01	<0.52					1	mg/l	lb/day			1
41B. N-Nitrosodimethylamine (62-75-9)				<0.01	<0.52					1	mg/l	lb/day			1
42B. N-Nitrosodi-N-Propylamine (621-64-7)				<0.01	<0.52					1	mg/l	lb/day			1

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	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (*continued*)															
43B. N-Nitrosodiphenylamine (86-30-6)				<0.01	<0.52					1	mg/l	lb/day			1
44B. Phenanthrene (85-01-8)				<0.01	<0.52					1	mg/l	lb/day			1
45B. Pyrene (129-00-0)				<0.01	<0.52					1	mg/l	lb/day			1
46B. 1,2,4-Trichlorobenzene (120-82-1)				<0.01	<0.52					1	mg/l	lb/day			1
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			X												
2P. α-BHC (319-84-6)			X												
3P. β-BHC (319-85-7)			X												
4P. γ-BHC (58-89-9)			X												
5P. δ-BHC (319-86-8)			X												
6P. Chlordane (57-74-9)			X												
7P. 4,4'-DDT (50-29-3)			X												
8P. 4,4'-DDE (72-55-9)			X												
9P. 4,4'-DDD (72-54-8)			X												
10P. Dieldrin (60-57-1)			X												
11P. α-Enosulfan (115-29-7)			X												
12P. β-Endosulfan (115-29-7)			X												
13P. Endosulfan Sulfate (1031-07-8)			X												
14P. Endrin (72-20-8)			X												
15P. Endrin Aldehyde (7421-93-4)			X												
16P. Heptachlor (76-44-8)			X												

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1. POLLUTANT AND CAS NUMBER (*if available*)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (*optional*)		
	a. TESTING REQUIRED	b. BELIEVED PRESENT	c. BELIEVED ABSENT	a. MAXIMUM DAILY VALUE		b. MAXIMUM 30 DAY VALUE (*if available*)		c. LONG TERM AVRG. VALUE (*if available*)		d. NO. OF ANALYSES	a. CONCENTRATION	b. MASS	a. LONG TERM AVERAGE VALUE		b. NO. OF ANALYSES
				(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS	(1) CONCENTRATION	(2) MASS				(1) CONCENTRATION	(2) MASS	
GC/MS FRACTION – PESTICIDES (*continued*)															
17P. Heptachlor Epoxide (1024-57-3)			X												
18P. PCB-1242 (53469-21-9)				<0.001	<0.052					1	mg/l	lb/day			1
19P. PCB-1254 (11097-69-1)				<0.001	<0.052					1	mg/l	lb/day			1
20P. PCB-1221 (11104-28-2)				<0.001	<0.052					1	mg/l	lb/day			1
21P. PCB-1232 (11141-16-5)				<0.001	<0.052					1	mg/l	lb/day			1
22P. PCB-1248 (12672-29-6)				<0.001	<0.052					1	mg/l	lb/day			1
23P. PCB-1260 (11096-82-5)				<0.001	<0.052					1	mg/l	lb/day			1
24P. PCB-1016 (12674-11-2)				<0.001	<0.052					1	mg/l	lb/day			1
25P. Toxaphene (8001-35-2)			X												1

Docket No. 20180007-EI
Application for EPD NPDES Permit GA0035564 Renewal for Plant Scherer
Exhibit MWS-6, Page 135 of 165

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

NPDES Industrial Permit Application Addendum

Please check the applicable box and enter the associated information:

☐ New discharger Name of facility:

☒ Existing NPDES discharger Name of facility: Plant Scherer Existing NPDES Permit No.: GA0035564

SECTION I. CONTACT & FACILITY INFORMATION

Permit Application Contact Name (first & last): Jean Brown	
Title: Environmental Specialist	
E-mail Address: jeabrown@southernco.com	
Total Design Flow (MGD): 172 (DIF)	Actual Design Flow (MGD):
Facility Latitude/Longitude (ex. 34.5364, -84.8045): 33.06 -83.807	EPA Major (circle one): *yes* or (*no*)
Primary Industry (circle one): (*yes*) or *no*	NAICS Codes: 221112

SECTION II. EFFLUENT LIMITS AND CONDITIONS

1. Is there an effluent limit, standard, guideline, or categorical pretreatment standard established for this type of discharge in 40 CFR Part 400-471, as amended or elsewhere pursuant to 301, 306, 307, 316, 318, or 405 of the Clean Water Act?

☒ Yes ☐ No

If you answered "yes", to question No. 1 above, please complete the following table below by providing the name of the discharge category and the specific citation to the regulation, if applicable, that establishes the limitation or condition.

If you answered "no" to question No. 1 above, please proceed to Section No. III.

Section II, Table No. 1

Name of Discharge Category and Appropriate Citation From State of Federal Regulations.	Effluent Limitation or Condition: (Yes or No)	Name of Subpart and Appropriate Subpart Citation
Example: ***Iron and Steel Manufacturing; 40 CFR Part 420***	***Yes***	***Acid Pickling; 40 CFR part 420 subpart I***
Steam Electric Power Generating Point Source Category	Yes	40 CFR Part 423

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2. Are any of the applicable effluent limitations applicable to the discharge(s) expressed in terms of production?

☐ Yes ☒ No

If you answered "yes", complete the following table below. For an existing discharge, list an actual measurement of your average or maximum level of daily production. For new discharges, list an average or maximum projected daily production. (indicate in the table whether the production figures given are average or maximum level.) Express the production in terms and units used in the applicable discharge limitation. Attach additional sheets if necessary.

If you answered "no" to question No. 2 above, please proceed to Section III.

Section II, Table No. 2 – Applicable Effluent Limit Guidelines

Name of Category and Subpart	Name and Quantity of Product per Day with Units of Measure	Description of Process	No. of Cycles through Process
Example: ***40CFR Part 420 Subpart I. Iron and Steel Manufacturing; Hydrochloric Acid Pickling***	***27,000 lbs of stainless steel strips (average)***	***Stainless steel strips are passed through solder flux baths in #1 Tinner***	***2***

SECTION III. WATER QUALITY

1. Name of Georgia major river basin(s) in which your discharge(s) enters: Ocmulgee

2. Do you discharge to 305(b)/303(d) Listed Waters*?

☐ Yes ☒ No

If you answered "yes" to question No.2 above, please complete the Table No. 1 below.

If you answered "no" to question No. 2 above, please proceed to Section IV.

** Georgia's 305(b)/303(d) list can be found on EPD's website at the following web address:*
http://epd.georgia.gov/georgia-305b303d-list-documents

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Section III, Table No. 1 – Applicable Water Quality

Outfall Identification ID	Name of Receiving Waters	Is The Receiving Water: 1) Supporting The Designated Use; 2) Not Supporting The Designated Use; or 3) Assessment Pending.	If The Receiving Water(s) Is Not Supporting The Designated Uses, What Is It Listed For?
Example: 001	*Oconee River*	*2*	*Sedimentation and Mercury*

3. Is there an applicable Total Maximum Daily Load* (TMDL) for the receiving waters?

☐ Yes ☒ No

If you answered "yes" to question No. 3 above, complete the following table below. If you answered "no" proceed to Section No. IV.

** Georgia's list of TMDL's can be found on EPD's website at the following web address:*
http://epd.georgia.gov/total-maximum-daily-loadings

Section III, Table No. 2 – Applicable TMDL

Outfall Identification	Name of Receiving Water	Is your discharge listed in the TMDL?	Name and Year of TMDL
Example: Outfall 003	*Jacks Creek a tributary to Oconee River*	*yes*	*Zinc TMDL Report [2002]*

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SECTION IV. SUMMARY OF DISCHARGE ANALYSIS*

If you are a new industrial discharger, you may omit this Section of the NPDES Application Addendum and proceed to Section V. If you are an existing facility with an existing NPDES wastewater permit, please proceed to question No. 1 of this Section below.

1. Complete the following table with a summary of discharge analytical data from the *previous three (3) years*. To complete the table for renewals, refer to your existing permit; for other discharges previously permitted by EPD, refer to your previous authorization or permit. Reproduce and complete Section IV of the NPDES Application Addendum form for each outfall that you are proposing to renew.

Outfall Identification (as referenced on permit and monitoring report): 01 Final Discharge

Parameter	Maximum Loading (lbs/day)	Average Loading (lbs/day)	Maximum Concentration (units)	Average Concentration (units)	Number of Exceedances	Comments
Ex. BOD 5-day	*325*	*204*	*22 (mg/L)*	*45 (mg/L)*	*3*	
Ex. pH	*NA*	*NA*	*10.0 (max. s.u.)*	*7.3 (min. s.u.)*	*2*	
pH	NA	NA	7.6 (max. s.u.)	7.6 (avg. s.u.)	0	1/1/2015-12/31/2017
O&G	NA	NA	0.2 (mg/L)	0.1 (mg/L)	0	1/1/2015-12/31/2017
TSS	NA	NA	9.5 (mg/L)	1.7 (mg/L)	0	1/1/2015-12/31/2017

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SECTION V. 40 CFR 122.21(r) COOLING WATER INTAKE STRUCTURES

Does the Cooling Water Intake Structure Rule for Existing Facilities Apply?

Directions: Answer questions 1 through 4 below for your cooling water intake structure(s) (CWIS). If your answer to any one of these questions is "No", then the requirements of 40 CFR 125.94 through 125.99 do not apply to your facility, and you may proceed to Section No. X. However, the State reserves the right to establish BPJ requirements as allowed in 40 CFR 125.90(b) for facilities.

Note: If you are a new facility please contact the GA EPD.

1. Is the facility a point source that discharges under a NPDES permit to waters of the State?

☒ Yes ☐ No

If you answered "yes" to question No. 1 above, please proceed to question No. 2 below.

2. Is the cooling water intake structure withdrawing cooling water from waters of the State?

☒ Yes ☐ No

If you answered "yes" to question No. 2 above, please proceed to question No. 3 below.

Note: Obtaining cooling water from a public water system, using reclaimed water from wastewater treatment facilities or desalination plants, or recycling treated process wastewater effluent as cooling water does not constitute use of a cooling water intake structure.

3. Is the facility-wide design intake flow (DIF) for all cooling water intake structures at the facility greater than 2 MGD?

☒ Yes ☐ No

If you answered "yes" to question No. 3 above, please provide the facility-wide design intake flow (DIF) and actual intake flow (AIF) for all cooling water intake structures in box 3.a.

Note: Actual Intake Flow means the average volume of water withdrawn on an annual basis by the cooling water intake structures over the past three years

3.a.

DIF = 172 (mgd)

AIF = 52.9 (mgd)

4. Does the facility have an intake structure that withdraws more than 25 percent of the water for cooling purposes on an actual intake flow basis?

☒ Yes ☐ No

If you answered "yes" to question No. 4 above, please provide the AIF percentage used exclusively for cooling purposes in box 4.a.

4.a.

AIF = 87 %

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Additional Information for Facilities to which the CWIS Rule applies

Section VI of this addendum lists the application requirements for all facilities for which the CWIS rule applies. The bullets below provide additional directions for which of following Sections VII, VIII and/or IX may also apply

- If you answered "yes" to question nos. 1, 2, 3 and 4 ***and*** you have an *existing unit at an existing facility*; the Impingement Mortality Best Technology Available (BTA) Standard, Section No. VII, applies to your facility.

- If you answered "yes" to question nos. 1, 2, 3 and 4 ***and*** your facility has a new unit at an existing facility; the Impingement Mortality BTA Standard, Section No. VIII, applies to you.

- If you answered "yes" to question nos. 1, 2, 3 and 4 **and** your facility withdraws greater than 125 MGD on an actual intake flow basis then the Entrainment BTA Standard, Section IX also applies to your facility.

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What is the timing of the submission of information required in permit application under the 316(b) Rule? *(December 2014 EPA MEMO)*

If your permit expires prior to July 14, 2018, under 40 CFR Part 125.95(a)(2), a facility may request that the Director establish an alternative schedule for submission of some of the permit application information in 40 CFR Part 122.21(r), based on a showing of the owner or operator of the facility that it could not develop the information for which an alternative schedule is requested by the time required for the submission of the permit renewal application.

Please check the applicable box(s).

☐ I request the Director provide an alternative schedule for the submission of some of the permit application information in 40 CFR Part 122.21(r).

☒ I request the Director provide an alternative schedule for the submission of the following permit application requirements in 40 CFR Part 122.21(r).

- ☐ (2) Source water physical data
- ☐ (3) Cooling water intake structure data
- ☒ (4) Source water baseline biological characterization data
- ☐ (5) Cooling water system data
- ☐ (6) Chosen Method(s) of Compliance with Impingement Mortality Standard
- ☐ (7) Entrainment Performance Studies
- ☐ (8) Operational Status
- ☐ (9) Entrainment Characterization Study
- ☐ (10) Comprehensive Technical Feasibility and Cost Evaluation Study
- ☐ (11) Benefits Valuation Study
- ☐ (12) Non-water Quality Environmental and Other Impacts Study
- ☐ (13) Peer Review
- ☐ (H) All facilities must also submit with their permit application all information received as a result of any communication with a Field Office of the Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service.

☐ I do not request an alternative schedule for the submission of some of the permit application information in 40 CFR Part 122.21(r). I have included the applicable permit application information required in 40 CFR Part 122.21(r).

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SECTION VI. APPLICATION REQUIREMENTS FOR ALL EXISITNG FACILITIES

1. If you are an existing facility, then you are required to submit the following information in accordance with §122.21(r)(1)(ii)(A), as applicable, with your permit application.

Please check the box next to the required information which you are submitting with this application.

- ☒ (2) Source water physical data
- ☒ (3) Cooling water intake structure data
- ☐ (4) If applicable, Source water baseline biological characterization data
- ☒ (5) If applicable, Cooling water system data
- ☒ (6) If applicable, Chosen Method(s) of Compliance with Impingement Mortality Standard
- ☐ (7) If applicable, Entrainment Performance Studies
- ☒ (8) If applicable, Operational Status
- ☐ (H) All facilities must also submit with their permit application all information received as a result of any communication with a Field Office of the Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service.

2. If you are an existing facility that withdraws greater than 125 mgd actual intake flow (AIF), as defined at 40 CFR 125.92 (a), of water for cooling purposes, then you are required to submit the following information in accordance with §122.21(r)(1)(ii)(B).

Please check the box next to the required information which you are submitting with this application.

- ☐ (2) Source water physical data
- ☐ (3) Cooling water intake structure data
- ☐ (9) Entrainment Characterization Study
- ☐ (10) Comprehensive Technical Feasibility and Cost Evaluation Study
- ☐ (11) Benefits Valuation Study
- ☐ (12) Non-water Quality Environmental and Other Impacts Study
- ☐ (13) Peer Review
- ☐ (H) All facilities must also submit with their permit application all information received as a result of any communication with a Field Office of the Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service.

Note: If the owner or operator of an existing facility intends to comply with the BTA (best technology available) standards for entrainment using a closed-cycle recirculating system as defined at 40 CFR 125.92(c), the Director may reduce or waive some or all of the information required under paragraphs (r)(9) through (13) of this section. If you intend to comply with BTA standards for entrainment using closed cycle recirculating systems as referenced above, please contact EPD.

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3. If you are a new unit at an existing facility, as defined at 40 CFR 125.92(u), you must submit or update the following information in accordance with §122.21(r)(1)(ii)(D).

Please check the box next to the required information which you are submitting with this application.

- ☐ (4) If applicable, Source water baseline biological characterization data
- ☐ (5) Cooling water system data
- ☐ (6) If applicable, Chosen Method(s) of Compliance with Impingement Mortality Standard
- ☐ (7) If applicable, Entrainment Performance Studies
- ☐ (8) Operational Status
- ☐ (H) All facilities must also submit with their permit application all information received as a result of any communication with a Field Office of the Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service.

4. If you are a new unit at an existing facility, as defined at 40 CFR 125.92(u), not previously subject to part 125 that increases the total capacity of the existing facility to more than 2 mgd DIF, you must submit the following information in accordance with §122.21(r)(1)(ii)(E).

Please check the box next to the required information which you are submitting with this application.

- ☐ (4) If applicable, Source water baseline biological characterization data
- ☐ (5) Cooling water system data
- ☐ (6) If applicable, Chosen Method(s) of Compliance with Impingement Mortality Standard
- ☐ (7) If applicable, Entrainment Performance Studies
- ☐ (8) Operational Status
- ☐ (9) If total capacity increases to more than 125 mgd, Entrainment Characterization Study
- ☐ (10) If total capacity increases to more than 125 mgd, Comprehensive Technical Feasibility and Cost Evaluation Study
- ☐ (11) If total capacity increases to more than 125 mgd, Benefits Valuation Study
- ☐ (12) If total capacity increases to more than 125 mgd, Non-water Quality Environmental and Other Impacts Study
- ☐ (13) Peer Review
- ☐ (H) All facilities must also submit with their permit application all information received as a result of any communication with a Field Office of the Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service.

Note: If the owner or operator of an existing facility intends to comply with the BTA (best technology available) standards for entrainment using a closed-cycle recirculating system as defined at 40 CFR 125.92(c), the Director may reduce or waive some or all of the information required under paragraphs (r)(9) through (13) of this section. If you intend to comply with BTA standards for entrainment using closed cycle recirculating systems as referenced above, please contact EPD.

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SECTION VII. *BTA STANDARD FOR IMPINGEMENT MORTALITY FOR EXISTING UNITS AT EXISTING FACILITIES*

The final rule requires that existing facilities subject to this rule must comply with one of the following seven alternatives listed below identified in the national BTA standard for impingement mortality at § 125.94(c) (hereafter, impingement mortality standards).

Note: Please check the box under the applicable impingement mortality standard in which your facility currently has in operation or intends to install to comply with the referenced standard. Please also provide the appropriate documentation for the chosen alternative and attach it your application.

1. Operate a closed-cycle recirculating system as defined at § 125.92;

☒ Currently in operation ☐ Request a compliance schedule

2. Operate a cooling water intake structure that has a maximum through screen design intake velocity of 0.5 fps or less;

☐ Currently in operation ☐ Request a compliance schedule

3. Operate a cooling water intake structure that has a maximum through screen intake velocity of 0.5 fps;
   a) In the case of Option (3), which EPA considers to be a streamlined alternative, the facility must submit information to the Director that demonstrates that the maximum intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 feet per second.

☐ Currently in operation ☐ Request a compliance schedule

4. Operate an offshore velocity cap as defined at § 125.92 that is installed before October 14, 2014;

☐ Currently in operation ☐ Request a compliance schedule

5. Operate a modified traveling screen that the Director determines meets the definition at § 125.92(s) and that the Director determines is the best technology available for impingement reduction;
   a) In the case of Option (5), the facility must submit a site-specific impingement technology performance optimization study that must include two years of biological sampling demonstrating that the operation of the modified traveling screens has been optimized to minimize impingement mortality. As discussed below, if the facility does not already have this technology installed and chooses this option, the Director may postpone this study till the screens are installed (see VI.G.1.d below).

☐ Currently in operation ☐ Request a compliance schedule

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6. Operate any other combination of technologies, management practices and operational measures that the Director determines is the best technology available for impingement reduction; or

(a) In the case of Option (6), the facility must submit a site-specific impingement study including two years of biological data collection demonstrating that the operation of the system of technologies, operational measures and best management practices has been optimized to minimize impingement mortality. If this demonstration relies in part on a credit for reductions in the rate of impingement already achieved by measures taken at the facility, an estimate of those reductions and any relevant supporting documentation must be submitted. The estimated reductions in rate of impingement must be based on a comparison of the system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody.

☐ Currently in operation ☐ Request a compliance schedule

7. Achieve the specified impingement mortality performance standard.

(a) The impingement mortality performance standard in (7) requires that a facility must achieve a 12-month impingement mortality performance of all life stages of fish and shellfish of no more than 24 percent mortality, including latent mortality, for all non-fragile species that are collected or retained in a sieve with maximum opening dimension of 0.56 inches and kept for holding period of 18 to 96 hours. The Director may, however, prescribe an alternative holding period.

The 12-month average of impingement mortality is calculated as the sum of total impingement mortality for the previous 12 months divided by the sum of total impingement for the previous 12 months. A facility must choose to demonstrate compliance with this requirement for the entire facility, or for each individual cooling water intake structure. Biological monitoring must be completed at a minimum frequency of monthly.

☐ Currently in operation ☐ Request a compliance schedule

SECTION VIII. BTA STANDARDS FOR IMPINGEMENT MORTALITY AND ENTRAINMENT FOR NEW UNITS AT EXISTING FACILITIES

The owner or operator of a new unit at an existing facility must achieve one of two compliance alternatives under the national BTA standards for impingement mortality and entrainment for new units at existing facilities at § 125.94(e) (hereafter, new unit standards).

☐ Option No. 1

You must reduce AIF at the new unit, at a minimum, to a level commensurate with that which can be attained by the use of a closed-cycle recirculating system as defined at § 125.92(c)(1).

☐ Option No. 2

You must demonstrate to the Director that it has installed and will operate and maintain, technological or other control measures that reduce the level of adverse environmental impact from any cooling water intake structure used to supply cooling water to the new unit to a comparable level to that which would be achieved through flow reductions commensurate with the use of a closed-cycle recirculating system. Under this alternative, the owner or operator of a facility must demonstrate entrainment mortality reductions that are equivalent to 90 percent or greater of the reduction that could be achieved through compliance with the first alternative entrainment standard for new units.

SECTION IX. ENTRAINMENT BTA

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The Director must establish the Entrainment BTA requirement for your facility on a site-specific basis in accordance with § 125.98(f)(2).

If you withdraw greater than 125 mgd AIF, you must develop and submit an Entrainment Characterization Study (§ 122.21(r)(9)), as well as provide other information required in § 122.21(r)(7) and (10), (11), (12) and (13) that must include specified data pertinent to consideration of several of the factors identified in § 125.98(f).

Please include your Entrainment Characterization Study as well as the other required information referenced above with your application.

SECTION X. CERTIFICATION

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.

Print Name: Mark Berry, Vice President - Georgia Power Environmental & Natural Resources	Date:
Signature of Applicant: Mark Berry	01/29/18

Plant Scherer, NPDES Permit No. GA0035564
Permit Renewal Application January 2018
316(b) Cooling Water Intake Structure (CWIS) Information

Plant Scherer employs a closed cycle cooling system for all four steam electric generating units. As such, it conforms to the Best Technology Available for both entrainment and impingement as described in the October 14, 2014 final 316(b) rule. The information provided below covers source water physical data, cooling water intake structure data, cooling water system data, and facility operational status as prescribed in 40 CFR 122.21(r)(2), (3), (5), and (8) respectively. A segment of the USGS 7.5 minute topographical map showing the location of Plant Scherer and the location of the intake structure is provided as Attachment A.

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

Plant Scherer withdraws cooling water from an impoundment of Rum Creek, which is a tributary of the Ocmulgee River with a watershed area of approximately 37 square miles. The impoundment, which is a Water of the United States, is known as Lake Juliette and provides storage for at least six months of full plant operation without supplemental pumping from the Ocmulgee River. Pumping from the Ocmulgee River is necessary to supplement inflow from the Rum Creek watershed area, and is limited by the Surface Water Withdrawal Permit during low river flows.

The normal operating level of Lake Juliette is 435'above Mean Sea Level and the bottom of the design storage is 415'. The surface area of Lake Juliette is 3,600 acres and usable storage volume is 53,700 acre-feet. Lake Juliette is located in the Rum Creek Wildlife Management Area (WMA), which is managed by the Georgia Department of Natural Resources. The WMA provides for extensive riparian zones throughout the lake, commonly more than 3000ft. There is no riparian vegetation in the immediate vicinity of the intake structure, although adjacent banks provide for approximately 200ft of riparian buffer.

Lake depths vary significantly, although typical depths of the lake fall between 20-35ft. Maximum depth is observed in the dam pool area and is approximately 70-80ft. Water depths at the intake structure vary depending on the operating level of the dam, but typical depths are approximately 32-35ft.

The elevations of the CWIS are included in the drawings in Attachment B.

Annual temperature regimes of Lake Juliette are a factor of ambient environmental conditions. Ambient lake temperatures are monitored under a seasonal monitoring program. Over the last three years, the maximum summer temperatures were measured between 28.5°C and 30.5°C, with winter minimums being between 7.5°C and 9.5°C. This data indicated that the temperature undergoes typical seasonal fluctuation associated with lakes in this region.

The hydraulic zone of influence has not been evaluated.

Plant Scherer, NPDES Permit No. GA0035564
Permit Renewal Application January 2018
316(b) Cooling Water Intake Structure (CWIS) Information

Cooling water intake structure (CWIS) data. 40 CFR 122.21(r)(3)

Plant Scherer has four coal-fired steam electric generating units, all utilizing closed cycle cooling systems with natural draft cooling towers. The Lake Juliette intake structure provides make-up water to supply cooling and process water to all four units. Each of six platform mounted pumps draws water through a traveling water screen to pressurize a Service Water System header which supplies the cooling water as well as process water. The common header has a minimum flow return line to Lake Juliette, such that the quantity of water pumped is larger than the quantity delivered to the units.

Design drawings of the structure are enclosed in Attachment B, as well as a water flow diagram as part of the NPDES application.

The structure is located at Latitude 33° 03' 14" and Longitude -83° 48' 22".

Cooling water system data. 40 CFR 122.21(r)(5)

The intake is in operation continuously 365 days per year to maintain pressure and supply the demand of any combination and dispatch level of the four units.

87 percent of the intake flow is to provide cooling water to the cooling system on the four units. The design circulating water flow for each unit is 386 mgd, or 1,545 mgd for all four units. The design make-up flow for all four units is 62 mgd. Therefore, the make-up flows drawn through the intake structure are 4% of the cooling system circulating water flow, demonstrating 96% reduction of flow that would be required through the intake if the system were once-through cooling. The systems are designed to operate at approximately 3 cycles of concentration. Additional Cooling Water Intake Structure information is provided in the NPDES Industrial Permit Application Addendum form.

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

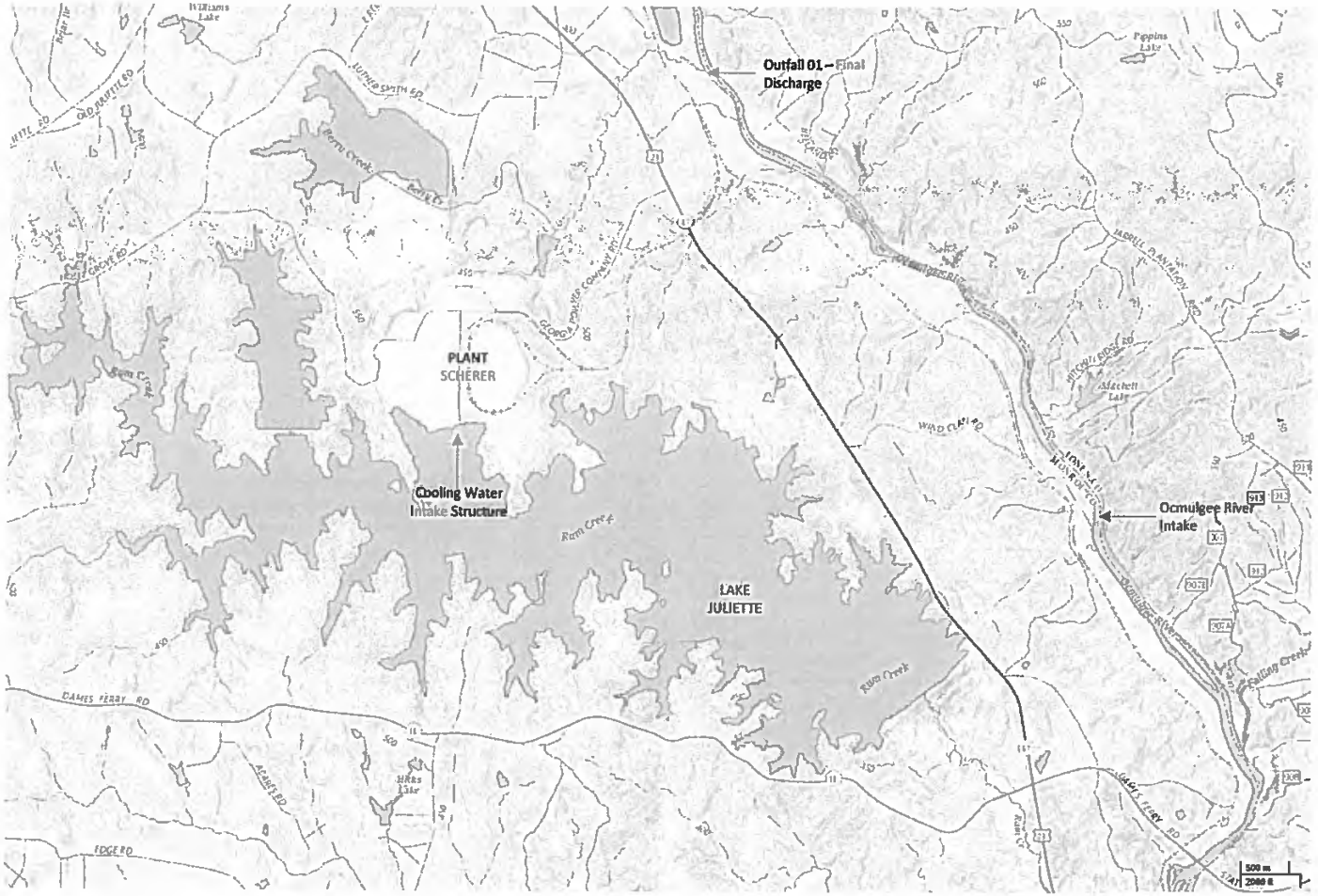
Unit	Nameplate (MW)	Age (years)	Fuel	Capacity Utilization Factor %				
				2012	2013	2014	2015	2016
1	818	35	Subbituminous Coal	68	64	73	52	57
2	818	33	Subbituminous Coal	71	67	62	59	51
3	818	30	Subbituminous Coal	66	56	61	42	53
4	818	28	Subbituminous Coal	66	86	58	77	59

Over the last 15 years the only major upgrades to the system have been condenser tube replacement on Unit 3 (2017) and Unit 4 (2016).

Plant Scherer, NPDES Permit No. GA0035564
Permit Renewal Application January 2018
316(b) Cooling Water Intake Structure (CWIS) Information

Attachment A

Plant Scherer Intake and Discharge Locations



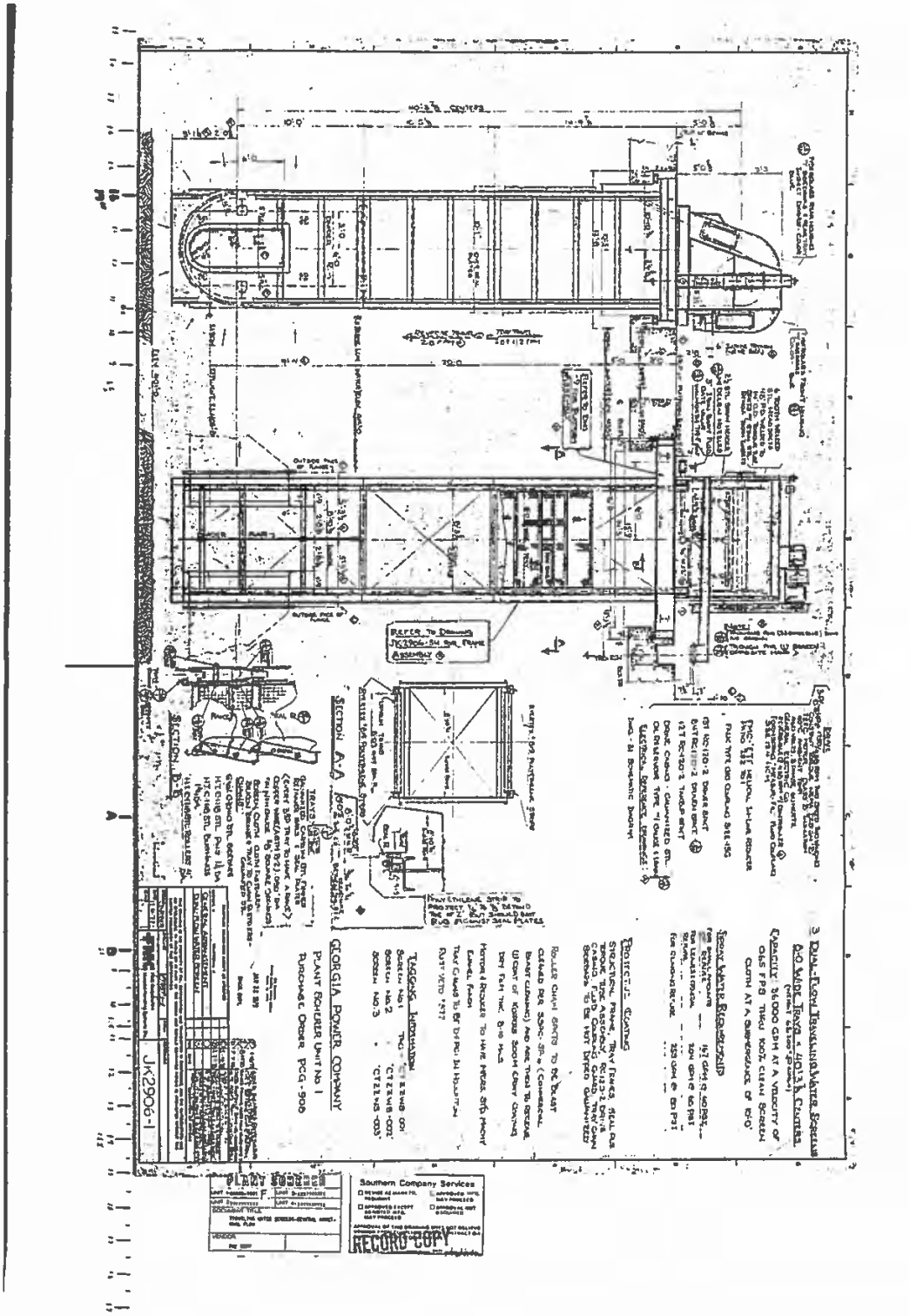
USGS 7.5 Minute - East Juliette Quadrangle

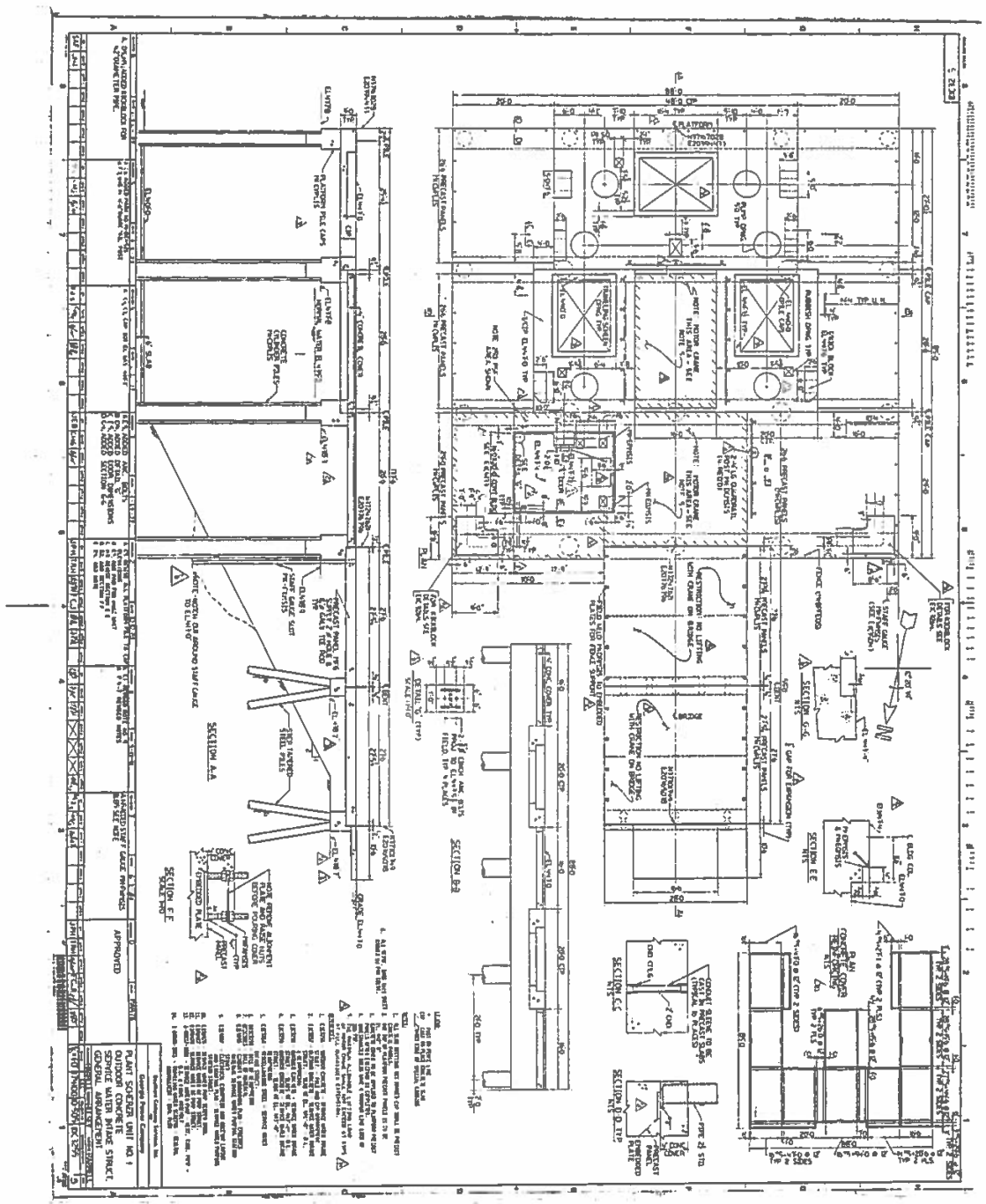
Plant Scherer Intake and Discharge Locations

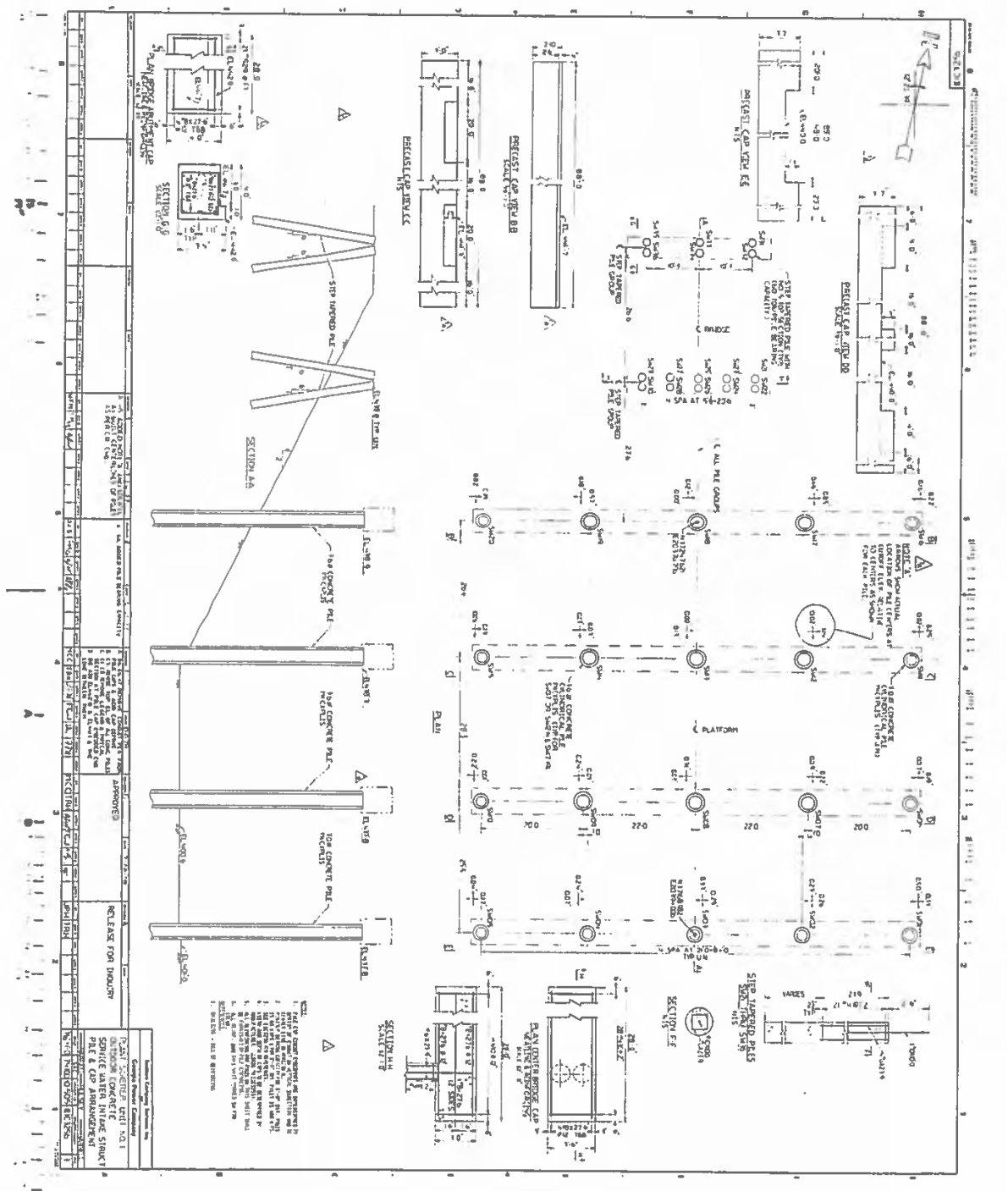


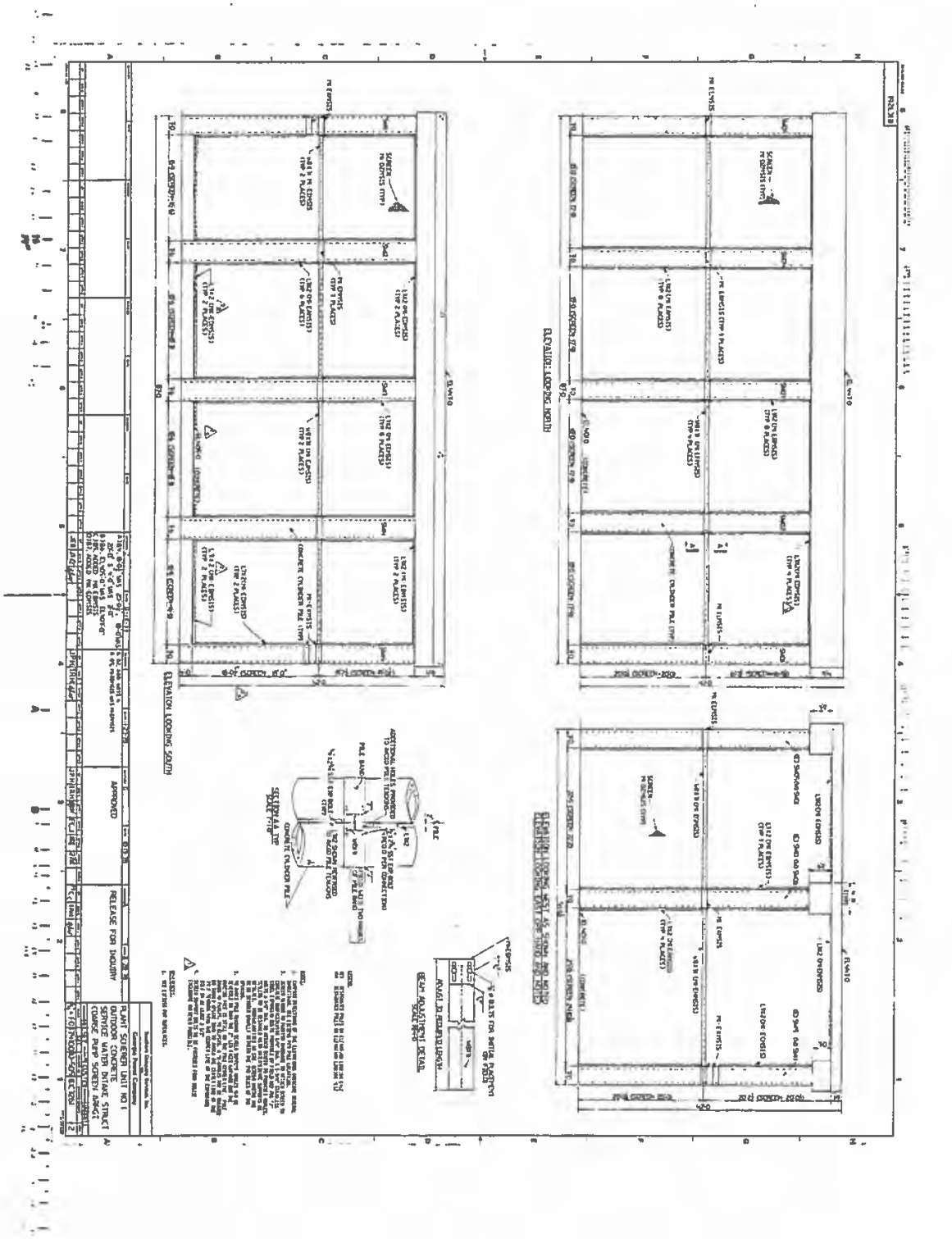
Plant Scherer, NPDES Permit No. GA0035564
Permit Renewal Application January 2018
316(b) Cooling Water Intake Structure (CWIS) Information

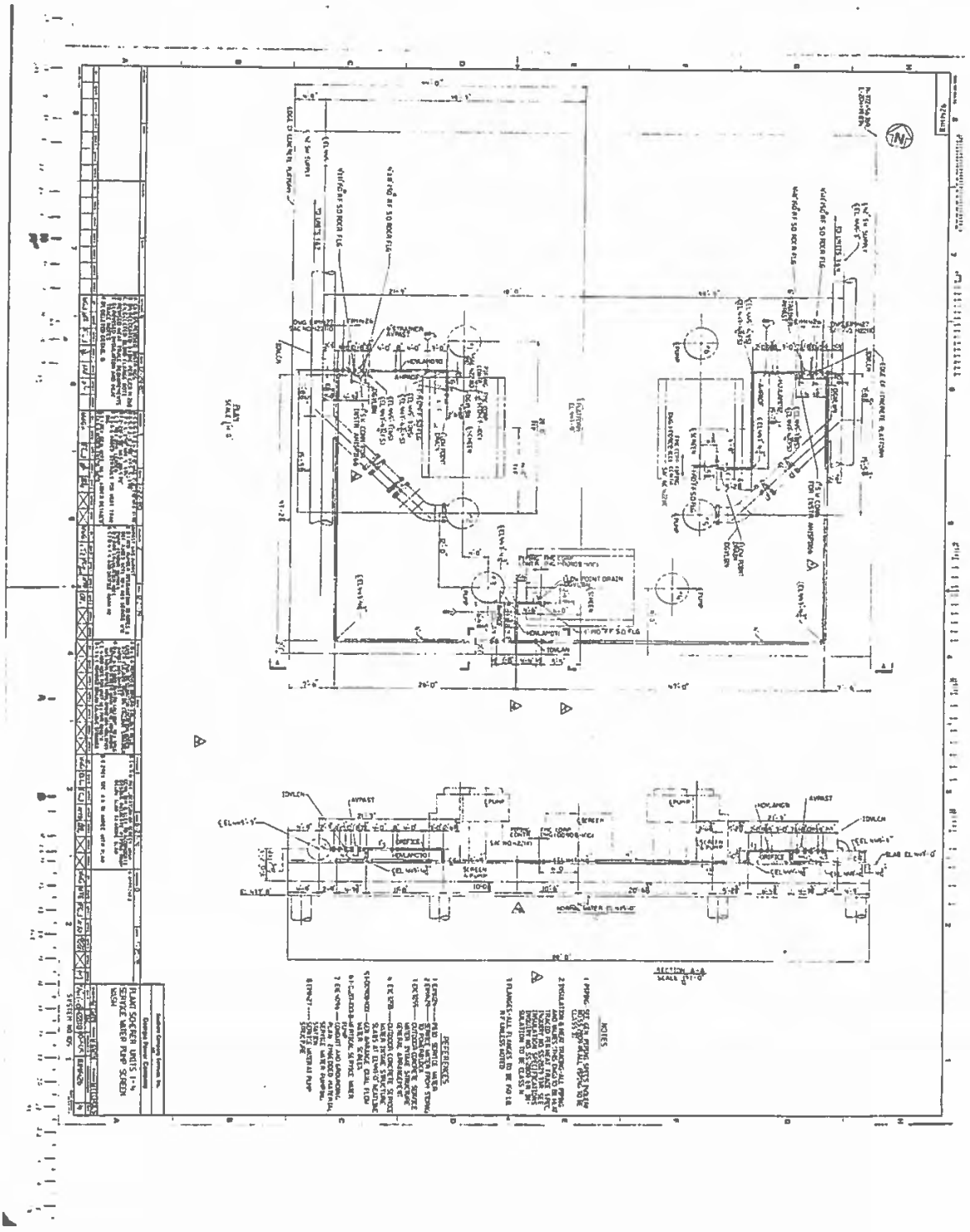
Attachment B


GEORGIA POWER COMPANY
PLANT ROHRER UNIT No. 1
TRAVELING WATER SCREEN
PURCHASE ORDER PCG-906
JK2906-1
Southern Company Services
RECORD COPY
PLANT SCHERER









Plant Scherer Effluent Limitation Guidelines Rule Applicability Timing NPDES Permit Application 2018

Background

This document details Plant Scherer's plans for addressing the revised Steam Electric Effluent Limitations Guidelines (ELGs), 80 Fed. Reg. 67,838 (Nov. 3, 2015), and the associated applicability dates for various waste streams being implemented in Plant Scherer's NPDES permit. Pursuant to the 2015 ELG rule, compliance with the new Best Available Technology (BAT) limitations in the final rule does not apply until a date determined by the Environmental Protection Division (EPD) that is "as soon as possible" beginning November 1, 2018, but that is also no later than December 31, 2023. However, on September 18, 2017, EPA modified the ELG rule by postponing certain applicability dates, 82 Fed. Reg. 43494 (Postponement Rule). The applicability dates relevant to Plant Scherer are as follows:

Fly Ash Transport Water (FATW)	November 1, 2018 through December 31, 2023
Bottom Ash Transport Water (BATW)	November 1, 2020 through December 31, 2023
FGD Wastewater (FGDW)	November 1, 2020 through December 31, 2023

Georgia Power encourages EPD to consider how best to approach implementation of the ELG rule, in light of the EPA Administrator's actions to postpone the applicability dates for BATW and FGDW. The preamble to the Postponement Rule makes it clear that it is EPA's intention to preserve the regulatory status quo and to avoid any unnecessary expenditures for compliance with limitations for BATW and FGDW, because those limitations may change as a result of further rulemaking. Given the further rulemaking being proposed; the Company requests that the Draft Permit refrain from addressing the applicability dates for BATW and FGDW, or in the alternative include language acknowledging the potential for changes and an associated permit reopener clause.

Based upon the existing rule, the phrase "as soon as possible" means November 1, 2018 for FATW, and November 1, 2020 for BATW and FGDW, unless a later applicability date is established. The "as soon as possible" date can be different for each waste stream. In order for EPD to determine the as soon as possible date within the implementation period, the ELG rule (80 Fed. Reg. at 67,883) identifies the following factors for EPD to consider:

1. Time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of the final rule;
2. Changes being made or planned at the plant in response to greenhouse gas regulations for new or existing fossil fuel-fired power plants under the Clean Air Act, as well as regulations for the disposal of coal combustion residuals under Subtitle D of the Resource Conservation and Recovery Act;
3. For FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment; and
4. Other factors as appropriate.

Section A of this document explains Georgia Power's ELG compliance evaluation. Sections B, C, and D address each of the factors identified by the ELG rule for assessing the "as soon as possible" date (as relevant). And, Section E addresses Georgia Power's proposed applicability timeframes.

A. ELG Compliance Evaluation

The ELG Rule's preamble (80 Fed. Reg. at 67,883-4) states that regardless of when a plant's NPDES permit is ready for renewal, the plant should immediately begin evaluating how it intends to comply with the requirements of the final ELGs. In cases where significant changes in operation are appropriate, the plant should discuss such changes with the permitting authority and evaluate appropriate steps and a timeline. Georgia Power has done that.

Georgia Power began evaluating how it intends to comply with the requirements of the ELG rule well before the rule's issuance in November 2015 (with effective date in January 2016). The company undergoes an ongoing comprehensive strategy development process involving many organizations within the company, including environmental, regulatory affairs, planning, fuels, engineering, finance, operations, communications, generation, and research groups. This strategy development process involves evaluating proposed and final environmental regulations to determine their impact to the generating fleet, conducting research to evaluate technology options for environmental control, developing compliance costs and schedules for capital environmental control technologies for regulatory compliance, and evaluating the impact of these costs to the company and its customers. In addition, and as explained further below, the Company has begun engineering work at Plant Scherer, which includes initial scoping of projects, design work, and in some cases commencement of construction.

Beginning in 2007, Southern Company Services began a R&D program focused on wastewater treatment technology development and demonstration. Over the last nine years, more than $20 million has been spent on R&D, including the construction of the Water Research Center (WRC) at Georgia Power's Plant Bowen. The WRC is a state-of-the-art facility focused on water reuse, recycle, conservation, and treatment. To date, over 20 projects have been completed at the WRC in key focus areas, including wastewater treatment, water conservation, and coal combustion residuals management.

B. Plant Scherer needs time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of the final ELG rule

The magnitude and complexity of process changes and new equipment installations that will be required for Plant Scherer to comply with the ELG rule and multiple other rule requirements is significant. The company must evaluate what operational changes are expected at Plant Scherer to meet the new BAT limitations, including the types of new treatment technologies that the plant needs to install, process changes anticipated, and the timeframe estimated to plan, design, procure, install, and optimize any relevant technologies. Moreover, consideration must be taken for the coordination of planned outages across the Southern Company generating fleet needed to install

new technologies and maintain electricity generation reliability. This all needs to occur in light of the reconsideration of the ELG's and in anticipation of those future regulatory requirements.

As noted above, Georgia Power maintains a robust annual environmental strategy and planning process that includes development of environmental compliance cost estimates for proposed and final regulations. Engineering cost estimates for each technology require constant revision based upon new information, as well as the continued evaluation of site-specific factors, such as the characterization of internal waste streams and their variability due to operational and seasonal changes. Using the engineering estimates, the regulatory interpretation, and the technology options available, cost-benefit analyses must be performed for each option. This analysis compares the costs and benefits of each option and their interplay with other system operating variables such as fuel costs. The analysis also must evaluate the costs and benefits of the most optimum compliance technology option against the option of retirement and replacement of the generation. These analyses include complex simulation models to forecast operating profiles, energy costs, impacts to the Georgia Power system production costs, and other factors for every affected unit using detailed unit-specific characteristics, such as heat rates; minimum and maximum capacity; up and down time; start-up costs; SO_X, NO_X, and CO_2 rates; fuel prices; and maintenance schedules. In addition to the operational profile outputs from the simulation models, financial calculations must be performed to evaluate impacts to total revenue requirements considering all incremental capital expenditures, plant O&M costs, transmission impacts, and any other peripheral requirements or costs. Georgia Power performs these economic analyses for each unit under multiple planning scenarios to capture a broad range of uncertainty in natural gas prices and CO_2 pressures.

As described above, many factors continue to be evaluated in order to develop a conceptual design for Plant Scherer. This evaluation is wastestream specific, cannot occur in isolation, and requires a holistic assessment of all the regulatory requirements at Plant Scherer as well as across Georgia Power's generating fleet.

C. Changes being made or planned at Plant Scherer in response to greenhouse gas regulations for new or existing fossil fuel-fired power plants under the Clean Air Act, as well as regulations for the disposal of coal combustion residuals under Subtitle D of the Resource Conservation and Recovery Act

It is clear that Plant Scherer is in the midst of an unprecedented period of uncertainty with respect to environmental regulations, such as the Clean Power Plan (CPP), federal Coal Combustions Residuals rule (CCR rule), the Section 316(b) Cooling Water Intake Structure rule (§ 316(b)), and other regulatory obligations. EPA finalized existing source greenhouse gas (GHG) emission guidelines, known as the Clean Power Plan (CPP), on October 23, 2015.

On February 9, 2016, the U.S. Supreme Court granted a stay of the CPP for the duration of the litigation. As a result of the stay, Georgia EPD, like many other states, suspended its work on the CPP for the duration of the litigation.

On March 28, 2017, President Trump signed the Energy Independence Executive Order, which directs agencies to review existing regulations that potentially burden the development of domestic

energy resources and suspend, revise, or rescind them, as appropriate. The Executive Order specifically directs EPA to review and take appropriate action on the CPP. On the same day, the U.S. Department of Justice, on behalf of EPA, filed a motion with the D.C. Circuit Court of Appeals to hold the CPP case in abeyance while EPA reviews the rule, as directed by the Executive Order.

On October 16, 2017, EPA proposed to repeal the CPP. In this proposal, EPA also notes it has not determined if it will issue a replacement rule or what form it will take. EPA stated it would issue an advanced notice of proposed rulemaking (ANPR) to solicit comments on the scope of a potential replacement rule and on December 28, EPA published the ANPR requesting ideas from the public on what a replacement rule for the CPP would look like. After EPA receives public comment on the ANPR, a possible next step would be EPA issuing a proposed replacement rule.

In light of these activities, the future of the CPP, or a replacement rule, and what it may require of existing power plants, is unknown at this time.

On April 17, 2015, EPA released publicly its final rule to regulate CCRs under Subtitle D of RCRA for nonhazardous waste. The rule became effective on October 19, 2015 and applies to: (i) new and existing CCR landfills and surface impoundments, including any lateral expansions of such units that dispose or otherwise manage CCRs generated by electric utilities and independent power producers (IPPs); and (ii) inactive surface impoundments, located at an active electric utility or IPP, regardless of fuel currently used (i.e., natural gas, coal, or oil) at the facility to produce electricity. The final rule does not apply to: (i) CCR landfills that have ceased receiving CCR prior to October 19, 2015; (ii) CCR landfills and surface impoundments at electric utilities and IPPs that have ceased producing electricity prior to October 19, 2015; (iii) municipal solid waste landfills that receive CCR; and (iv) beneficial use of CCR. The CCR rule was "self-implementing," with enforcement from RCRA citizen suits.

The Georgia Board of Natural Resources adopted a final "Coal Combustion Residuals" rule on October 26, 2016. Georgia's final CCR rule establishes a new permitting program for all CCR units at electric utilities in the State. The rule took effect on November 22, 2016. On December 16, 2016, President Obama signed the Water Infrastructure Investment for the Nation Act (WIIN) (S. 612). The Act gives EPA enforcement authority for the federal CCR rule and authority to approve state permitting programs for CCR units. The Act also gives EPA authority to implement a federal permitting program in non-participating states. EPA's process for reviewing and approving state CCR permit submissions will be subject to a public notice and comment period. However, it is unclear if EPA will go through rulemaking to establish this process. The WIIN Act takes the federal CCR rule from a self-implementing rule to a permit-based rule.

The CPP, CCR Rule, § 316(b) rule, and other rules may require capital retrofit decisions that could result in unneccesary expenditures, stranded assets and/or permanent or temporary closures of facilities prior to the end of their useful life. Plant Scherer needs significant additional time to gain more certainty regarding these rules to determine the most appropriate compliance option to ensure that safe, reliable, and affordable electricity is provided to our customers.

The factors provided for in the 2015 rule have been bolstered by the recently promulgated ELG Postponement Rule. As mentioned previously, on September 18, 2017, EPA issued a final rule

postponing the near-term applicability dates for FGDW and BATW from November 1, 2018, to November 1, 2020. 82 Fed. Reg. 43,494. EPA's stated purpose for the Postponement Rule is to authorize permit writers to select applicability dates that will avoid any expenditures to comply with the 2015 ELGs for FGD wastewater and BATW until EPA completes further rulemaking for those waste-streams. As such, achieving the central purpose of the Postponement Rule means that EPD must use the November 1, 2020 deadline (the date by which EPA intends to complete the rulemaking) as the starting point, not the endpoint, for compliance expenditures. The preamble accompanying the Postponement Rule indicates that EPA will conduct further rulemaking to revise the applicability dates if it has not completed its reconsideration of the FGDW and BATW limits by November 1, 2020.

D. Other Factors and Waste-Stream Specific Considerations

(i) Bottom Ash Handling

Significant factors influence the implementation schedule of dry bottom ash retrofits at Plant Scherer. These retrofits are site-specific, with little opportunity for modularization or standardized designs to accelerate the schedule. Furthermore, engineering and construction labor resources will likely be strained, due to the number of similar projects being undertaken in the Southern Company fleet and nationwide. Plant Scherer has already completed the technology selection and design process for bottom ash conversions. Plant Scherer is installing Magaldi systems which are completely dry bottom ash handling systems. These systems are scheduled for completion in 2019.

(ii) Fly Ash Handling

Dry fly ash handling infrastructure is already in place at Plant Scherer, however additional testing and minor infrastructure improvements are required to ensure reliable operations. The system will undergo additional testing prior to the earliest implementation date of the ELG rule. Compliance with the updated ELG's is anticipated at the beginning of the applicability timeframe.

(iii) Flue Gas Desulfurization Wastewater (FGDW)

As mentioned previously, Southern Company and its partners, the Electric Power Research Institute (EPRI), Southern Research Institute (SRI) and 14 other companies, created a state-of-the-art Water Research Center (WRC) that focuses on finding new ways to reduce, conserve and improve the quality of water returned to the environment from power plants.

One major area of WRC focus has been evaluating EPA's chosen BAT for FGDW, which is physical chemical treatment followed by GE's ABMet technology. In addition, several other technologies have been under evaluation at the WRC to treat and discharge FGDW to ELG limits. These include technologies from Frontier Water Systems, Inotec, Evoqua, Liberty Hydro, and an in-house Biofilm technology. To date,

no technology, including the EPA's BAT has consistently or reliably met the final ELG limits. Testing has shown an approximate 75 to 80% compliance rate at the WRC with the two most promising technologies. It should be noted that those compliance rates were: 1) based upon pilot scale tests; 2) do not accurately reflect the FGDW treatability characteristics that may be encountered in the future; and 3) were not performed for Plant Scherer's FGDW. Southern Company has also been exploring technologies to eliminate the discharge of FGDW. Traditional thermal Zero Liquid Discharge (ZLD) technologies such as falling film evaporators have proven to be unreliable around the industry; therefore, novel concepts and technologies are being developed and demonstrated. These technologies are not commercially demonstrated on a utility scale at this time and need further development and demonstration.

Due to the immature nature of the available effective compliance options, grid reliability could be significantly impacted. FGD wastewater technology limits based on biological treatment or ZLD are not consistently achievable and, if prematurely implemented in NPDES permits, could cause numerous compliance issues and forced plant outages. In addition, tie-in outages during installation will need to be staggered and coordinated with those required for other projects in order to maintain the reliability of the plant and the grid.

A single FGDW treatment system with physical, chemical, and biological treatment will take, on average, four years to complete detailed design engineering, procurement of equipment and materials, and construction. Southern Company will likely need to install eight treatment systems for 27 units that have FGDs. The detailed engineering of these systems is unique and based upon site-specific factors. Therefore, the use of standardized designs and modular construction techniques may not be practical given the unique nature of each design. This lack of leverage will require dedicated engineering teams working on parallel timelines. The availability of engineering resources, as well as construction labor, will be stretched with the abundance of projects across the industry. Procurement of equipment and material lead times will increase as market demand outpaces vendor supply. The market pressures will be exacerbated by the fact that there are very limited process suppliers available whose biological systems come close to meeting all proposed FGDW limits.

EPA's record demonstrates that plants installing the FGDW treatment BAT spent several months optimizing its operation (initial commissioning period). To assure the plant can reliably and consistently meet the new FGD limitation in all seasons, it will need time between equipment startup and the compliance date to optimize system performance. Variability across operations and waste stream characteristics impacts treatability; therefore, a minimum optimization period of 12 months is anticipated.

Again, FGDW considerations listed above should be coupled with EPA's postponement of the compliance dates and the potential future rulemaking for this wastestream. These factors all combine and justify Plant Scherer's proposed FGDW applicability date of late 2023.

E. Georgia Power's Proposed Applicability Timeframes

Georgia Power and Plant Scherer have consistently complied with all environmental regulations, and Plant Scherer's compliance with the 2015 revision to the Effluent Limitation Guidelines is no exception. With that said, and as detailed above, the regulation specifically considers the planning, design, engineering and operational constraints with regard to implementation timing. Georgia Power has spent significant time and resources on assessing the compliance options with the revised ELG's at Plant Scherer and all of the generating plants, and this effort will continue. These efforts will also occur in conjunction with EPA's ELG reconsideration process, ELG Postponement Rule, and potential future ELG rulemaking.

At this time, Georgia Power is able to commit to the following ELG applicability dates at Plant Scherer:

Fly Ash Transport Water per § 40 CFR 423.13(h)	January 1, 2019
Bottom Ash Transport Water per § 40 CFR 423.13(k)	November 1, 2020
Flue Gas Desulfurization Wastewater § 40 CFR 423.13(g).	December 31, 2023

Georgia Power

Mark S. Berry
Vice President
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February 28, 2018

By E-Mail

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Mike Burroughs, Gulf Power Company (MLBURROU@southernco.com)
Charles Howton, Gulf Power Company (CTHOWTON@southernco.com)

Re: Plant Scherer Condenser Tube and Cooling Tower Packing Replacement Projects

Dear Co-Owners:

I am writing to follow up on discussions on the condenser tube and cooling tower packing replacement projects at Plant Scherer. As both operator of Plant Scherer and as an owner of several units at Plant Scherer, Georgia Power Company ("Georgia Power") operates Plant Scherer in accordance with all applicable regulations and prudent utility practice. Completing appropriate condenser tube and cooling tower packing replacement projects at each of Plant Scherer's units during each unit's currently planned outage in 2018 and 2019 will position Plant Scherer for the continued environmental compliance of Plant Scherer and is a key part of long-term equipment maintenance activities for Plant Scherer.

Each unit at Plant Scherer has undergone or will undergo condenser tube and cooling tower packing replacement projects over the next two years during its scheduled outage. All projects should be completed by the end of 2019. At Plant Scherer and at its other plants, Georgia Power takes its environmental compliance record seriously, and Georgia Power believes the condenser tube and cooling tower packaging replacement projects are vital to long-term continued generating efficiency and regulatory compliance at Plant Scherer.

If you have any questions, please contact me at 404-506-7777.

Sincerely,

Mark S. Berry

cc: Johnny J. Howze, Plant Manager, Plant Scherer, Georgia Power Company
Scott Smith, Generation Support Manager, Georgia Power Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 8
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Michael W. Sole MWS-7

Alachua County
Department of Growth Management

Office of Planning and Development

Steven Lachnicht, Director

DEVELOPMENT REVIEW COMMITTEE ORDER DR-17-04

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 9
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Michael W. Sole MWS-8

Property Owner: Florida Power and Light Company

Agent: Gunster, Yoakley & Steward, P.A.

In the above numbered Order, the Development Review Committee took the following action on **February 16, 2017**:

Approved Project 2016082903, a **Preliminary and Final Development Plan, a Floodplain Development Permit, Issuance of a Final Certificate of Level of Service Compliance and Waiver from Section and half-section line setbacks** for **Florida Power and Light - Project Horizon** the construction of a 74.5 MW photovoltaic solar facility on approximately 489.01 acres of project area east of County Road 219A and north of County Road 1474, **as per staff recommendation with conditions as follow:**

1. FP&L shall maintain a performance bond, as outlined and approved by the BoCC on 2/14, until the extinguishment or subordination of all existing mortgages or liens. A failure to fulfill this requirement constitutes a violation of this development order and may, at the election of the County, result in termination of the final development order.

2. The clearing and grading or construction permit shall not be issued until the following items have been addressed:
   a. Demonstrate that protective fencing and/or erosion/sedimentation barriers have been installed adjacent to the CMA.
   b. Provide a copy of the recorded Conservation Easement to EPD.

3. The applicant has indicated that FPL intends to utilize the wells during construction and appropriately cap them following construction. Prior to final release of site, provide EPD documentation that the wells have been properly plugged and abandoned in the form of completed well registration forms (406.66, 406.67, ULDC) and copies of well completion reports.
4. Landscape Irrigation Design and Maintenance Standards, Article II of Part II, Title 7, Chapter 79 of the Alachua County Code went into effect 4/1/16. All new irrigation systems installed in unincorporated Alachua County now require County approval **prior to installation**, which includes a review fee and site plan. All systems will then go through an inspection process. The Alachua County Irrigation Professional Portal has been created to allow irrigation professionals to submit required documents and pay fees entirely online. For those who are not online, required information may be submitted on paper in person at the EPD office at 408 West University Ave in

Gainesville, 8:30-5:00 Monday through Friday. For more information about the Landscape Irrigation Efficiency Code and for a list of helpful resources, we encourage you to click HERE. For more information, contact Water Resources staff at 352-264-6800 or at Irrigation@AlachuaCounty.us.

5. The applicant shall obtain all required state and federal permits prior to commencement of the development. Upon issuance of a required state or federal permit, the applicant shall furnish a copy of such permit to the applicable County department.

6. FPL will conduct avian mortality monitoring and reporting at the existing FPL Desoto solar PV facility, utilizing a study design developed in coordination with the Florida Fish and Wildlife Conservation Commission and consistent with the methodology described in USGS Open File Report 2016-1087, Mortality Monitoring Design for Utility-Scale Solar Power Facilities. The monitoring protocol shall be in place and monitoring shall begin during 2017 and results will be provided to Alachua County. If FPL does not initiate the study at Desoto by the end of 2017, FPL shall conduct the study in Alachua County at the Horizon site, commencing no later than January 1, 2018.

7. The applicant shall be required to maintain CR 219A from US 301 to SR 26 and CR 1474 from US 301 to the Putnam County Line during construction. The applicant shall notify the Public Works Department a minimum of five business days prior to the commencement of construction so that the Department can evaluate the condition of the roadway. The limits of maintenance may be amended if the County is provided with a specific haul route for delivery of materials necessary for construction. Prior to the final release of the site, the applicant shall restore this roadway to pre-existing conditions as determined by the Public Works Department.

In reaching this decision and order, the Development Review Committee has considered all matters presented to it including the written reports by departments of the County which are filed in the official file in the Growth Management Department and information presented at the hearing and has found the proposed application to be consistent with the Alachua County Comprehensive Plan and Unified Land Development Code.

Signed this 16th day of February 2017

Ivy M. Bell

Ivy M. Bell
Development Review Committee Chair

ALACHUA COUNTY
DEVELOPMENT REVIEW COMMITTEE

Beth Scrivener

Beth Scrivener
Development Review Clerk

Date: 02/16/2017

Protocol for monitoring avian mortality at solar energy facilities in Florida

Juan C. Oteyza[1], Andrew Cox[2], Brett Tornwall[2], Jason Wagman[1], Jason Hight[1], Jennifer Goff[1]

[1] Division of Habitat and Species Conservation, Conservation Planning Services, Florida Fish and Wildlife Conservation Commission
[2] Fish and Wildlife Research Institute, Florida Fish and Wildlife Conservation Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 10
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Michael W. Sole MWS-9

October 2017

Florida Fish and Wildlife Conservation Commission
Division of Habitat and Species Conservation &
Florida Fish and Wildlife Research Institute
620 South Meridian Street
Tallahassee, FL 32399

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Protocol for monitoring avian mortality at solar energy facilities in Florida

Summary

Utility-scale solar energy is projected to greatly increase in the United States and the state of Florida. Despite the benefits of solar energy, there is the potential for negative impact on avian communities. Birds have been documented colliding with panels, which may lead to direct mortality or leave individuals stunned and vulnerable to predators (Kagan et al. 2014). Waterbirds in particular can confuse the reflection of polarized light off of photovoltaic cells (PV) for water (Horváth et al. 2010, Smith and Dwyer 2016) which can lead to injury through direct impact or stranding for those species that require water to take off (e.g. grebes). However, as large solar arrays are fairly new to the landscape, few studies have performed systematic monitoring that allows for rigorous quantification of avian mortality (WEST 2014, H.T. Harvey and Associates 2015), and little supporting data exists in the peer-reviewed literature (McCrary et al. 1986, Walston et al. 2016). Furthermore, studies resulting in publicly available documents have historically focused on high production-capacity facilities in arid areas in the southwestern United States (WEST 2014, Walston et al. 2015a; H.T. Harvey and Associates 2015). Given these potential impacts and the geographic focus of existing studies, monitoring for avian mortality at solar energy facilities in Florida is recommended.

In order to facilitate assessment of avian mortality at solar energy facilities in Florida, this document outlines necessary considerations for a monitoring protocol and follows with more specific recommendations for the DeSoto Next Generation Energy Center, a photovoltaic solar facility in DeSoto County. Recommendations focus on photovoltaic (PV) arrays and not on other sources of solar energy production (i.e. concentrated solar power). Monitoring for avian mortality at PV facilities in Florida is expected to be difficult because (a) carcass detection may be hindered by dense vegetation, (b) carcasses may not persist in the environment for long due to numerous and diverse scavengers, and (c) mortality rates associated with PV panels may be low. Combined, these factors reduce the overall carcass detection probability. One efficient way to increase carcass detection and reduce the uncertainty around the fatality estimate is by increasing searcher efficiency. Searcher efficiency can be increased by using detection dogs, which will also help reduce other aspects of survey effort. A web-based application was developed to determine the minimal survey frequency (how often the facility is searched) and the extent of the sampling fraction (proportion of the facility searched) for obtaining sufficiently precise estimates (https://hermes475.shinyapps.io/newplotconditional/). This application simulates scenarios under different monitoring conditions and displays the level of precision of the mortality estimate associated with those scenarios. To make these simulations realistic, they have to be informed by estimates of searcher efficiency and carcass persistence that are based on experimental trials performed on-site. Monitoring is recommended during each of the four annual seasons to account for the diversity and abundance of birds throughout the year in Florida. The suggested approach, combined with the provided simulation tool, will help determine the minimal effort necessary to obtain avian mortality estimates at the desired level of precision.

Background

Utility-scale solar energy is projected to greatly increase in the United States and the state of Florida. There are substantial benefits to solar energy, such as reduced toxic and carbon emissions compared to non-renewable sources of energy, but despite these benefits there is the potential for negative impact on a variety of bird species. Given these potential impacts, monitoring for avian mortality at solar energy facilities is recommended. Because development of utility-scale (several megawatt capacity) solar arrays are relatively new, few studies have performed systematic monitoring that allows for rigorous quantification of avian mortality (WEST 2014), and little supporting data exists in the peer-reviewed literature (McCrary et al. 1986, Walston et al. 2016).

There are two main types of utility-scale solar energy installations: concentrating solar power (CSP) which use reflectors to concentrate solar energy to heat a receiver, and photovoltaics (PV) which use cells to convert sunlight directly into electric current (Walston et al. 2016). Avian mortality has been reported at both types of facilities (reviewed in Walston et al. 2015a). Bird mortality at CSP facilities can occur due to burning or singeing when birds are exposed to the solar-flux (i.e. concentrated sunlight; Kagan et al. 2014). Collision trauma can occur when birds can collide with reflective surfaces (PV panel or reflector) which may lead to direct mortality or leave individuals stunned and vulnerable to predators (Kagan et al. 2014). Water birds may be particularly at risk where photovoltaic cells (PV) reflect polarized light and give the impression of water (Hováth et al. 2010, Smith and Dwyer 2016). If such a "lake effect" occurs (Kagan et al. 2014), mortality could be a consequence of impact with the panels when birds descend to land or birds could become stranded since some species require water for take-off, leaving them vulnerable to starvation or predation (Kagan et al. 2014). Evidence of a lake effect as a source of mortality is scarce. For example, only three water bird carcasses were found (a low proportion of the total) at the approximately 1,586-acre, 250MW California Valley Solar Ranch, a PV solar energy facility (H.T. Harvey and Associates 2015). But given the lack of habitat for these species and their very low abundances around this arid site, H.T. Harvey and Associates (2015) concluded these birds likely died due to collision and by confusing the arrays with a body of water. Ultimately, occurrence of bird mortalities may depend on bird population abundances and the land-type context around the facility, but evidence for avian mortality at any type of solar facility is not always collected in a systematic and rigorous way which makes quantification and comparisons across facilities difficult (Walston et al. 2015a).

The purpose of this protocol

Studies have described the potential negative effects of solar energy on birds and bird communities as both direct (e.g. fatality due to collision) or indirect (e.g. impact on habitat conditions; Lovich and Ennen 2011, Hernandez et al. 2014, Walston et al 2015a, 2016). This approach focuses on the direct impacts of utility-scale solar energy because other considerations (e.g. siting) are made at earlier stages by the landowners, usually when performing an Environmental Assessment, a pre-construction survey as part of a Bird and Bat Conservation Strategy (BBCS; e.g. WEST 2014) or similar analyses. In contrast, post-construction mortality monitoring is equivalent to the tier 4 monitoring of the Land-based Wind Energy Guidelines established by the USFWS (2012). That is, the concern is not with site evaluation and characterization, pre-construction monitoring, or mitigation decisions. Instead this protocol is intended to serve as a general guideline to solar energy developers on how to monitor for avian

mortality in a systematic and rigorous way that allows for representative mortality estimates to be obtained and ultimately for cross-facility comparisons. These guidelines are focused on the impact of the solar array (the PV solar panels) on birds and do not consider the effect of other infrastructure (transmission lines, perimeter fences, buildings, inverters, etc.) since guidelines already exist for those (e.g. the Avian Power Line Interaction Committee's Reducing Avian Collision with Power Lines [2012]). The focus here is on PV technology and not on other types of solar energy because PV is the main technology projected to expand in the state of Florida in the near future.

A bibliography of peer-reviewed and gray literature papers , including technical reports from the private sector and government agencies is included as Appendix A (based on literature available as of May 2017). This bibliography collects evidence of avian mortality associated with utility-scale solar energy and papers that discuss methods for estimating mortality. Many of the methods used for estimating mortality come from other sectors, mainly wind energy where the impact on birds and bats has been studied extensively, and have been used to differing degrees in the solar energy sector. This methodological focus of the bibliography complements the bibliography by Walston et al. (2015b).

Evidence of avian mortality at PV facilities

Avian mortality at utility-scale PV facilities has been recorded for a variety of bird taxa, including ducks, wading birds, shorebirds, and songbirds, among others (WEST 2014, Walston et al. 2015a). Most records come from technical reports of consulting companies monitoring at facilities with high production-capacity (e.g. 250 - 550MW at California Valley Solar Ranch, Desert Sunlight, and Topaz Solar Farm), which have been summarized elsewhere (WEST 2014, Walston et al. 2015a; see also H.T. Harvey and Associates 2015). However, our understanding of how birds and PV arrays interact is limited because few of these studies have performed systematic mortality monitoring while accounting for carcass detection biases. Furthermore, comparisons across sites are challenging because some facilities have not yet published results and/or facilities differ in methodological approaches (such as survey design and length of monitoring periods). Additionally, these studies are limited in geographic scope as most of the publicly available documents come from facilities in arid areas in southwestern United States (California and Nevada).

One of the most rigorous avian mortality monitoring efforts available to date suggests that mortality can be substantial at PV facilities. Researchers at the 250MW California Valley Solar Ranch estimated that >500 avian mortality events occurred in a single year, even after controlling for background mortality rates determined from study of nearby conservation areas (H.T. Harvey and Associates 2015). Their results are summarized in more detail in table 1. Fatality estimates were greater for small than for large birds, and for winter compared to fall estimates. These results, and those from others (Kagan et al. 2014, WEST 2014), indicate that mortality due to collision can occur at solar energy facilities –albeit, it is likely lower than that associated with other energy sources, including wind (WEST 2014). Additionally, collision risk may differ across facilities, birds of different size classes, and seasons.

Table 1. Mortality estimates at California Valley Solar Ranch based on a one year monitoring period between November 2013 and November 2014 (data from H.T. Harvey and Associates 2015).

Annual mortality based on a	Number of	Estimated	90% Confidence

one year monitoring period	carcasses used in mortality estimate	mortality	Interval
Mortality for *known* causes throughout the facility[1]	40	126	106 – 155
Mortality for *unknown*[2] causes throughout facility	186	2598	2116 – 3334
Mortality for *unknown*[2] causes within the arrays	150	2314	1890 – 2965
Mortality for *unknown*[2] causes for each tracker (a total 1032 solar panel tracking units/plots)	NA	2.24	1.83 – 2.87
Mortality across control plots (30 plots similar in size to a solar tracking unit)	14	52	31 – 81
Estimated mortality per control plot	NA	1.72	1.05 – 2.68
Mean background-adjusted per-tracker fatality rate for *unknown*[2] cause	NA	0.51	-0.83 – 1.81
Mean background-adjusted mortality within the array for *unknown*[2] cause	NA	526	----

[1] Including incidental finds, bird mortality associated with infrastructure other than the solar panels, and control plots that were used to monitor background avian mortality.
[2] Determining the cause of mortality is often difficult. In this study the cause of mortality of the majority (80.9%) of birds could not be identified. Necropsies were not performed and are generally necessary to identify if a bird died from collision trauma.

Avian mortality at solar energy facilities varies in magnitude and species composition across facilities (as evidenced in a comparison of three facilities by WEST [2014]). Differences may in part depend on local habitat features, such as the presence of ponds or wetlands, and bird abundances around the facility. These factors may interact with processes occurring at a larger geographic scale, such as winter or short-distance migration. For example, higher proportion of migrant mortality were reported for the spring than during other times of the year at Ivanpah Solar Electric Generating System in California, a CSP solar energy plant (Walston et al. 2015a). Thus, each solar energy facility is unique in its conditions and may require independent monitoring.

Several factors make solar development in Florida different from that in southwestern United States, and these need to be considered when developing avian mortality monitoring approaches. Most sites planned for Florida in the near future have smaller production capacity, generally ≤75MW (compare to the 250MW at California Valley Solar Ranch, used in the example above). Smaller facilities tend to have smaller footprints and may have lower overall avian mortality rates. Bird species composition, diversity, and density likely differs between Florida and the arid southwestern U.S., which could also affect risk of mortality. For example, Florida may have higher abundance of wading or water-associated birds which could increase mortality if there is a "lake effect" with solar arrays (Kagan et al. 2014). On the other hand, bodies of water are less limiting in Florida than they are in arid regions, potentially making solar arrays less alluring to birds in this state. Similar to California/Nevada, Florida has high solar

radiation but with much higher precipitation and humidity. The conditions in Florida favor fast and dense vegetation growth which may be associated with higher bird abundances around the facility and which can make carcass detection around the panels difficult. Additionally, denser vegetation around the panels could offer more nesting opportunities for birds. Whether these nesting sites could offer benefits or disadvantages to birds remains unclear.

Quantifying avian mortality at energy facilities is an imperfect process because of our inability to continuously monitor throughout space and time. Several factors make this detection process imperfect, and these factors should be understood in order to adequately estimate mortality. This document contains two sections: (1) a general description of these factors and important considerations to establish a post-construction monitoring protocol to estimate avian mortality at solar energy facilities in the state of Florida. (2) An example of how this protocol could be implemented at the DeSoto Next Generation Energy Center, in Arcadia, FL.

1. Considerations for estimating avian mortality at solar energy facilities

Post-construction monitoring guidelines for avian mortality at solar energy facilities build on those developed for the wind energy sector (e.g. Land-based Wind Energy Guidelines established by the USFWS 2012, Kunz et al. 2007a), and preliminary guidelines exist from the USGS and USFWS (Huso et al. 2016a). Current efforts exist to develop standardized protocols to monitor avian mortality at solar energy facilities, such as those by The Multiagency Avian-Solar Working Group (2016), the U.S. Fish and Wildlife Service (USFWS), and the U.S. Geological Survey (USGS). These efforts may lead to new guidelines to be implemented in the state of Florida. Meanwhile, this document and the accompanying simulation application (https://hermes475.shinyapps.io/newplotconditional/) will serve as an initial step towards developing rigorous post-construction monitoring protocols to estimate avian mortality as utility-scale PV solar energy facilities.

Factors affecting the overall detection probability

Several factors make bird carcass detection an imperfect process and decrease detection probability. Additionally, logistical and budgetary constraints may limit the ability to comprehensively monitor a facility across space and time. These are the factors that must be considered when quantifying avian mortality:

- ***Searcher efficiency*** – proportion of carcasses found by the searcher out of all carcasses in the search area. The ability to find carcasses can be affected by carcass size, vegetation cover, location relative to the panel, weather, etc. (Huso 2010).
- ***Carcass persistence*** – average number of days a carcass persists before it decays or it is removed by a scavenger. Also expressed as the probability a carcass persists to the following day. Similar to searcher efficiency, carcass persistence can be affected by factors such as carcass size, vegetation cover, and weather.
- ***Sampling fraction*** – Technically, the proportion of dead birds that fall into the searched area. However, given that carcass distribution is assumed to be homogeneous, operationally sampling fraction is the proportion of the facility or area covered during the survey.
- ***Duration*** – period of time over which surveys take place (e.g. throughout the year, eight weeks each season, etc.). Even though duration only reflects length of time, if surveys are not year-round, timing within a year is important to consider. Not only bird mortality probability can vary with season but also carcass detection can change, for example, with seasonal vegetation changes.
- ***Survey Frequency*** – time interval between each survey. That is, number of days between sampling sessions which occur within the *duration* period (e.g. every four days.)
- ***Mortality*** (or ***count***) – number of carcasses found in the search area.

In addition to the factors that influence carcass detection, it is important to determine the *desired level of precision* of the mortality estimate because the desired precision will have a major influence on the monitoring strategy. The level of precision to achieve a general understanding of the order of magnitude of facility-caused avian mortality is usually far less than the level needed for testing hypotheses (Huso et al. 2016a). Researchers often use a coefficient of variation (i.e., the ratio of the standard deviation to the mean estimate) to gauge the precision of mortality monitoring because it is independent of the magnitude of the measured effect. In general, the necessary precision to broadly understand what the total number of bird fatalities is

may result in a coefficient of variation of 20-30% (Strickland et al. 2011). If the focus of the study is specific (e.g. state or federally listed) species, and/or the anticipated magnitude of the impacts is low (i.e. very low mortality rates) an increased level of precision may be required. An increased level of precision can be achieved by increasing search effort or increasing the overall detection probability (USFWS 2012, Huso et al. 2016a).

Searcher efficiency and ***carcass persistence***

Both *searcher efficiency* and *carcass persistence* need to be empirically measured by following existing protocols (as described in Huso et al. 2016a; Smallwood 2007, 2010, 2013, and those described in WEST 2016, H.T. Harvey and Associates 2015). These trials require deliberately placing carcasses in the search area and measuring 1) the searcher's ability to find them and 2) the persistence of undisturbed carcasses on the ground over time. *Searcher efficiency* and *carcass persistence* trials need to be performed at each facility where mortality wants to be estimated. Independent trials need to be performed because many conditions vary across sites, including: differences in vegetation (both within and around the facility), differences in the community of carcass scavengers, differences in the types of perimeter fences, use of different searchers (customarily each searcher undergoes his/her own searcher efficiency trials), among others. Additionally, trials should be performed each season the carcass surveys will be performed. This is standard because conditions vary across seasons (e.g. vegetation changes influence searcher efficiency, and scavenging rates can fluctuate seasonally), affecting *searcher efficiency* and *carcass persistence* (e.g. Osborn et al. 2000, Smallwood et al. 2010, Villegas-Patraca et al. 2012, Hull and Cawthen, 2013, Reyes et al. 2016).

Searcher efficiency and *carcass persistence* trials should include bird carcasses of different sizes, generally small, medium, and large. At least small and large birds should be used (for example, representative of a songbird and an egret) as these size differences will markedly affect both *searcher efficiency* and *carcass persistence* estimates (Osborn et al. 2000, Arnett et al. 2010, Smallwood 2007, 2013). Commonly, *searcher efficiency* and *carcass persistence* of small birds tends to be much lower than for large birds. Yet, small birds are important to consider given that they can represent a large portion of bird mortality at PV facilities. A review of three PV solar facilities in western United States found that close to 50% of bird carcasses found across these sites were from songbirds (Passeriformes; WEST 2014). Ideally, carcasses of local birds should be used or, in the case of using surrogates, care should be taken to avoid using unusually conspicuous species (Smallwood 2007, WEST 2016). Other considerations, such as the use of fresh carcasses (Smallwood 2013), minimizing carcass manipulation and using latex gloves, avoidance of predator swamping (Smallwood 2007), carcass location relative to the panel unit (Visser 2016), etc. are described thoroughly in Bird and Bat Conservation Strategies and reports such as WEST (2016), H.T. Harvey and Associates (2015), and Huso et al. 2016a.

In some cases, no actual carcass is found, but scavengers may leave behind feathers indicating a bird was caught or consumed and these "feather spots" should be counted as carcasses. A feather spot is usually defined as a set of feathers above a certain threshold; for example, ≥10 feathers within one square meter (Erickson et al. 2004, Smallwood 2007, Reyes et al. 2016; see recommendations by the California Energy Commission and California Department of Fish and Game 2007) or at least five tail feathers, or two or more primary flight feathers within five m or less of each other (H.T. Harvey and Associates 2015, WEST 2016). Detection of feathers with significant amounts of skin, flesh, or bone attached are generally not categorized as feather spots but as partial carcasses (H.T. Harvey and Associates 2015). Reyes et al. (2016)

suggest inclusion of feather spots as a category (its own carcass size class) for trials as these tend to be harder to detect as corroborated during searcher efficiency trials. For example, only one feather spot in 43 were detected in trials by Stevens et al. (2011). When used, detection dogs should be trained to detect feather spots as well as carcasses (Reyes et al. 2016).

Carcass persistence is generally outside the control of researchers because it depends on the scavenger community and carcass decomposition rates. The appropriate perimeter fencing could potentially reduce the number of scavengers, but may be ineffective against coyotes if they can dig and crawl under a fence, against smaller meso-predators (such as raccoons and opossums) that can easily climb fences, or against birds and invertebrates. Given the diversity of small and medium sized mammals, birds, and invertebrates (e.g. fire ants), carcass persistence may be relatively low in subtropical Florida compared to more northern latitudes where most of these trials have been performed (mostly for the wind energy sector; e.g. Crawford and Engstrom 2001, Villegas-Patraca et al. 2012). If measures are taken to mitigate carcass removal by scavengers, such as improvement of fences or crow control/deterrence measures, these should be put in place prior to a monitoring season and continued throughout monitoring to avoid dramatic changes in carcass persistence during the monitoring season.

Unlike *carcass persistence*, *searcher efficiency* can generally be influenced by researchers. There are primarily two approaches to increase *searcher efficiency*: frequent mowing of vegetation to maximize line of sight to carcasses, and the use of detection dogs. Determining which approach is best will depend on a variety of factors, not the least of which is the relative cost of the two approaches. Mowing is likely more expensive and might also bias results, as an increased mowing frequency relative to what is customary at a facility would result in mortality monitoring under atypical conditions (i.e., artificially low vegetation that may or may not attracts or deters birds and/or influence mortality rates; Korner-Nievergelt et al. 2011). Additionally, if there are any birds nesting in these grasses, an increase in mowing frequency may impact their reproductive success.

An alternative approach is the use of detection dogs to find carcasses. Dogs have been shown to greatly increase searcher efficiency, particularly in areas of dense vegetation. For example, during trials, dogs found 73% of all bat carcasses whereas humans found 20% (Mathews et al. 2013). Similar results were found when searching for birds (Arnett 2006, Homan et al. 2001, Paula et al. 2011, Boroski et al. 2016, Reyes et al. 2016). Dogs could search the facility under the conditions of a regular mowing schedule provided that *searcher efficiencies* are also measured under those varying conditions. Additionally, solar panels obscure ground visibility under one side of the panel (true for both fixed position and tracking systems panels during monitoring hours) and dog searches based on olfaction may help mitigate this problem (WEST 2016). Dogs may be particularly effective in humid environments, like Florida, compared to dry environments such as those in the southwestern U.S. where dry air presented problems (Reyes et al. 2016). In all cases, environmental conditions during carcass searches should be taken into account and later used as covariates in search efficiency estimates, since factors such as wind variability or moisture may negatively affect carcass detection ability by dogs (Shivik 2002). Additionally, wind direction should be taken into account during searches with dogs and ideally searches will be performed while moving upwind to increase chance of detection (Mathews et al. 2013). Dog training techniques, including types and number of carcasses used, and details on how to perform search efficiency trials, should follow thorough studies such as Reyes et al. (2016).

Using dogs may require running survey transects along the length of the panel rows instead of using distance sampling and walking perpendicular to panel rows (Huso et al. 2016a). Walking along panel rows may be more effective because running transects perpendicular to the panel rows with tall vegetation would require truncation of the transect width due to rapid decrease of detectability with distance (effectively reducing the *sampling fraction*). Whichever approach is taken, walking along or perpendicular to panel rows, the same approach should be used during *searcher efficiency* trials and during mortality surveys. However, the simulations performed here do not use distance sampling to inform the estimates and assume a thorough survey approach will be taken (i.e. walking along panel rows). Ultimately, increasing *searcher efficiency* is recommended as it will allow reduction of the *sampling fraction* and increase precision of the estimate.

Whether the mowing schedule becomes more regular or detection dogs are used, vegetation is assumed to be relatively homogeneous across the *sampling fraction* and closely matching the vegetation during the *searcher efficiency* trials. Another way that vegetation around the panel has been controlled is by using sheep. If sheep are used, vegetation is likely to be more variable and therefore it may be particularly important to observe that vegetation during the *searcher efficiency* and *carcass persistence* trials is representative of the vegetation during facility monitoring. To do so, trials and monitoring will likely need to occur concurrently in order to achieve a robust mortality estimate.

Researchers have three options for temporally matching searcher efficiency and carcass persistence trials with mortality monitoring. First, trials could start and end prior to monitoring for mortality in the facility. This approach is not recommended as it may not appropriately characterize conditions while monitoring is taking place. Second, trials could start simultaneously with and occur concurrently with facility monitoring. This approach may help minimize cost and logistical burden but it requires a thorough and more conservative monitoring protocol at first, until trial parameters are estimated and monitoring is adjusted accordingly. The resulting estimates obtained using this approach will be more representative of the season (e.g. as vegetation cover increases or searcher skills improve) and avoid scavenger satiation (setting out too many carcasses at once may overwhelm scavengers and misrepresent scavenging rates). The third option is recommended where trials could start prior to mortality monitoring in order to obtain values that will inform the study design and staff needed, and continue concurrently with facility monitoring. Once regular mortality monitoring begins (while *searcher efficiency* and *carcass persistence* trials continue), study design may be adjusted to obtain the desired level of precision. Of course, to avoid biases, searchers should not be aware of when trials vs. actual monitoring are taking place and trial-carcass location should be undisclosed to the searchers. Each searcher, human or canine, should undergo their own searcher efficiency trials.

The estimates obtained in *search efficiency* and *carcass persistence* trials at each site will determine the *sampling fraction*, *duration* and *frequency*. For example, the survey *frequency* (how often surveys will take place) directly depends on the *carcass persistence*. If carcasses persist for 15 days on average, then the survey *frequency* should be sufficient to be able to find the majority of those carcasses (≥50%) before they disappear (e.g. about every 10 days; Strickland et al. 2011). Conversely, a low *carcass persistence* would require high survey *frequency*. Therefore, establishing a single protocol to use across sites which vary in carcass persistence would not be cost effective. A facility where conditions are not favorable to estimate mortality may require a more thorough monitoring protocol, but that same protocol may be

excessive and unnecessarily costly for a facility where conditions are more favorable (e.g. one with high carcass persistence). Since information was not available on the possible *searcher efficiencies* and *carcass persistence* rates at different sites, a web-based application (app) was created to simulate possible scenarios with varying values of these parameters. These simulations serve as a tool to provide insight into optimal *survey frequency* and *sampling fraction* at a given solar energy facility given the *searcher efficiency* and *carcass persistence* trials performed on that site. The app and instructions for running the simulations can be found at https://hermes475.shinyapps.io/newplotconditional/.

Duration of the survey period
Whenever feasible, an adaptive approach should be taken where carcass searches would be performed more intensively for the first few years (e.g. first two years, as in WEST 2016) and depending on the resulting mortality estimates, carcass searches could increase, decrease or cease altogether in subsequent years. At least two years of intensive monitoring would be recommended to account for potential differences across years (e.g. in precipitation and bird movements; Borkhataria 2009), especially because mortality rates during the initial years post-commissioning (immediately after the land has been disturbed) may differ from mortality on subsequent years (after vegetation has recovered). In addition, prolonged drought conditions could affect estimates by decreasing bird abundance and consequently the estimates of mortality may not be representative of periods of higher bird abundance (H.T. Harvey and Associates 2015).

Ideally, monitoring would occur throughout the year (e.g. WEST 2016, H.T. Harvey and Associates 2015, WEST 2016) with a survey *frequency* (e.g. every 5 days) dependent on *carcass persistence* (see below). Alternatively, surveys could take place on a seasonal basis to reduce monitoring costs without sacrificing temporal representation (e.g., one sampling period in each of the four seasons). Seasonal monitoring can make it difficult to calculate annual mortality rates but instead allows for four separate seasonal estimates that can be interpreted in a manner similar to how annual rates are interpreted. If four monitoring seasons take place and each lasts two months on average, this will deduct four months of monitoring out of the year.

Many wind energy studies have focused on spring and fall surveys to coincide with bird migrations which are thought to represent peaks in bird collision mortalities. However, timing surveys with migration in Florida might not provide a complete picture of mortality associated with PV arrays because birds are abundant year-round in Florida. Many species are non-migratory, many additional species breed in more temperate latitudes but winter in Florida, and other species are short-distance and/or facultative migrants that may follow movement patterns different from boreal migration schedules. For example, wading birds tend to follow changes in precipitation and water levels and, unlike songbirds, their movements across Florida may peak in November and late-Feb to mid-March; (Kahl 1964, Kushlan 1986, Comer et al. 1987, Breininger and Smith 1990, David 1994, Borkhataria 2009). Accordingly, H.T. Harvey and Associates (2015) found that within the array at California Valley Solar Ranch, mortality peaked in the winter months which also coincided with higher bird abundances. Therefore, a temporally representative sample should be taken in Florida, and this would require that at least four sampling periods take place across the year, covering all four seasons.

Temporal variation should be considered in bird abundances when planning a carcass monitoring timeframe. For example, spring migration tends to be more concentrated than fall

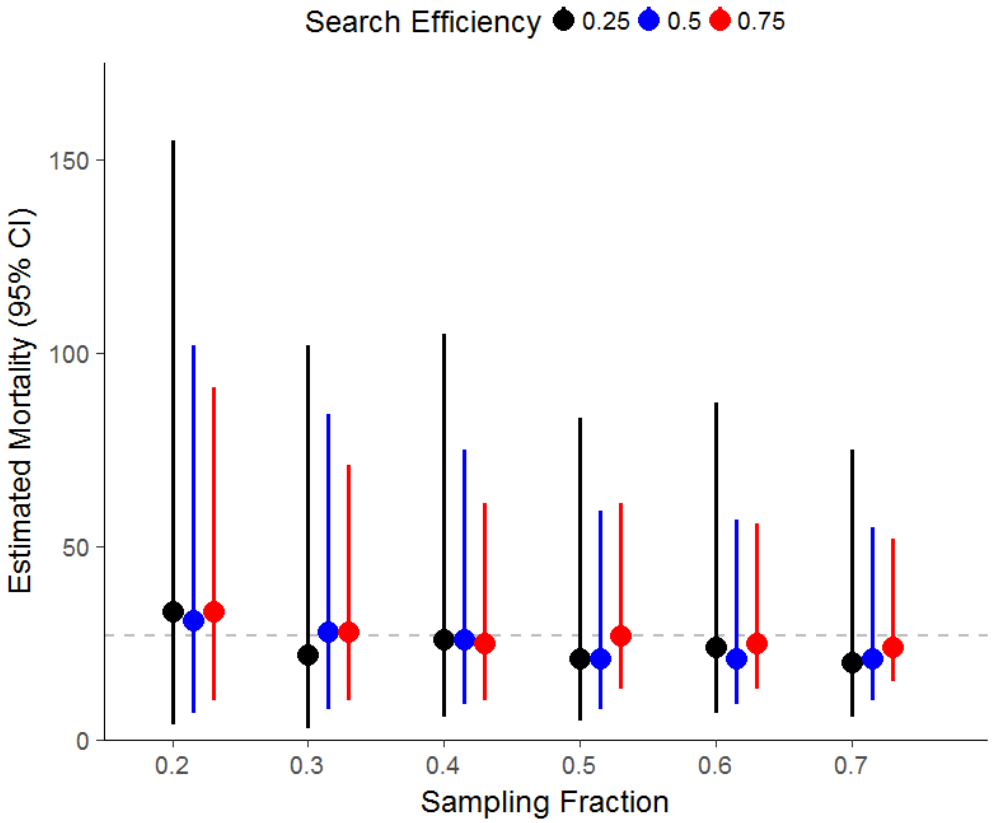
migration, and bird densities tend to be higher during fall migration because of the presence of hatch-year birds and because of the elliptical migration pattern of some species that cover parts of the state during the fall but not the spring (i.e. species may have different southbound and northbound routes; Ydenberg et al. 2007). Combined, these factors can affect bird mortality rates across seasons in Florida (Crawford and Engstrom 2001).

Nighttime versus daytime mortality can also vary. Since most birds are diurnal, most mortality will occur during the day which would suggest that surveys should take place late in the afternoon (before scavengers become active at dusk), as suggested by Kagan et al. (2014). Nocturnal mortality rates may vary depending on the type of activity, as some species forage at night (nocturnal species) while others migrate at night. Studies at three PV facilities, reported that 50-75% of the species (and 17.6-75.2% of individual fatalities) were of birds that migrate at night (WEST 2014). However, there was no indication that mortality occurred during nocturnal migration and some of the species reported also have resident (non-migratory) populations at these sites. Monitoring may need to be adjusted to account for nocturnal mortality; if mortality is high at night this may require early morning surveys (preferably starting at dawn to minimize scavenging which tends to be highest early in the morning; Crawford and Engstrom 2001). To assess which approach is most effective at detecting birds, monitoring and trials could take place in the morning and afternoon at the beginning of the season. Description of the carcasses found (e.g. species identification, presence of ants or *rigor mortis*, etc.) and careful consideration of the species' life history (including migratory strategies) will help inform which are the best monitoring times.

Sampling fraction

The goal of an efficient avian mortality monitoring effort is to minimize the effort required to produce robust estimates. This may be achieved by increasing *searcher efficiency*, because higher *searcher efficiencies* allow for a reduced *sampling fraction* (Fig. 1). A more thorough monitoring of the *sampling fraction* (e.g. walking along panel rows and using detection dogs) will increase carcass detection probability. Once *carcass persistence* and *searcher efficiency* trials have been performed, simulations with the provided app will help determine an adequate *sampling fraction* at each site. It may be necessary to survey around 25% to 50% of the facility to obtain accurate estimates, but this percent could increase if *searcher efficiency* proves to be poor and the number of carcasses found (count) is low (as found by our simulations and those by WEST [2016]).

Figure 1. Simulations showing the relationship between the proportion of the facility searched (sampling fraction) and its influence on the estimated mortality and its 95% confidence interval. All simulations were performed maintaining constant values of carcass persistence and associated error (0.8 ± 0.16), survey duration (8 weeks), survey frequency (3 days). The dashed line represents the true number of birds that died based on simulations (27 birds in 8 weeks). The points represent mortality estimates based on the Korner-Nievergelt et al (2011) estimator using package *Carcass* (Korner-Nievergelt et al 2015) in program R (R Core Team 2017). Variation in the point estimate partially reflect stochasticity implicit in the model. Colors represent scenarios with different searcher efficiencies (0.25, 0.5, and 0.75; black, blue and red, respectively). For details see note on page 26.



In general, the estimator performs well and the mortality estimates on Fig. 1 approximate actual mortality (all near the dashed line). However, as this figure shows, the confidence around that estimate decreases when the proportion of the facility that is searched decreases (i.e. more uncertainty with lower *sampling fraction*). This decrease in the confidence level is greater when *searcher efficiency* is low (black color). A simulation using 75% searcher efficiency (red color), shows less uncertainty as a larger area of the facility is sampled. That is, as the *sampling fraction* increases, the confidence in the estimate increases. But, in this example, increases beyond 0.4 (40% of the facility) result only in small increases in precision. For reference, landowners should aim for a high *searcher efficiency* (e.g. ~0.75; red color) which allows them

to maintain a relatively low search area (0.3-0.5) and still have relatively high confidence around the estimate.

Figures 1 and 2 are examples based on arbitrary carcass persistence rates and should not be used as a guideline to decide upon a desired survey *frequency* and *sampling fraction.* Instead, researchers can use FWC's web application to input the values derived from searcher efficiency and carcass persistence trials to create figures similar to those shown here (https://hermes475.shinyapps.io/newplotconditional/). These figures will serve as a guide to help determine the appropriate *sampling fraction* and *frequency* to choose given the desired precision.

Extrapolation of the mortality values from a *sampling fraction* to an entire facility requires that the *sampling fraction* be representative of the facility. The *sampling fraction* should be a simple random sample of the facility, with several search plots scattered throughout the facility. For an example see case study 3 in Huso et al. (2016a), showing the search protocol established by WEST (2015) at Desert Sunlight, California. Plots should include central parts of the arrays and the edges to avoid biases (WEST 2016). Plots close to the edge should be scattered throughout the facility, particularly if the habitat types around the facility differ as habitat type and degree of human activity could influence mortality rates and *carcass persistence*. One way to ensure a more spatially balanced sampling fraction is by stratifying the random sample. To do so, the facility can be subdivided into sections of equal size. Then an equal number of plots for each section is selected by using a simple random sample, ensuring a more homogeneous distribution of plots.

The *sampling fraction* should incorporate all aspects of the landscape and be representative of the facility as a whole. Injured birds may move from the area where they collide and into an area with more cover (e.g. under a panel, where vegetation is densest, to a pond, or under a nearby building or other structure), and these areas may be outside search plots. An even plot distribution will help mitigate this problem, particularly if using detection dogs, which are more likely to locate injured birds.

Survey frequency

The main determinant of survey frequency is carcass persistence (Fig. 2). An initial target could be set so that the survey frequency allows ≥ 50% of the carcasses to persist to the next search, and can be later adjusted once searcher efficiency and sampling fraction are calculated (Huso et al. 2016a). The optimal survey frequency should complement the *search efficiency* in order to achieve the target detection probability.

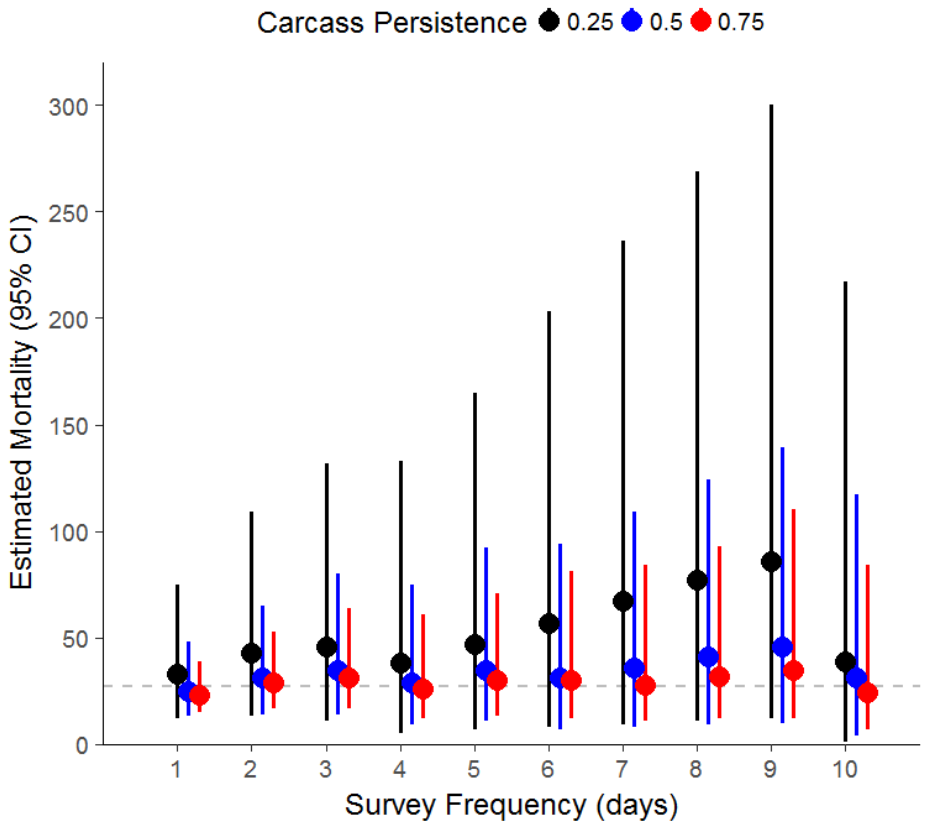


Figure 2. Simulations showing the relationship between search interval (survey frequency) and its influence on the estimated mortality and its 95% confidence interval. All simulations were performed maintaining constant values of searcher efficiency and its error (0.8 ± 0.16), survey duration (8 weeks), and sampling fraction (0.5 of the facility). The dashed line represents the true number of birds that died based on simulations (27 birds in 8 weeks). The points represent mortality estimates based on the Korner-Nievergelt et al (2011) estimator using package *Carcass* (Korner-Nievergelt et al 2015) in program R (R Core Team 2017). Variation in the point estimate partially reflect stochasticity implicit in the model. Colors represent scenarios with different carcass persistence (0.25, 0.5, and 0.75; black, blue and red, respectively). For details see note on page 26.

The estimator performs well and the mortality estimate approximates actual mortality (all near the dashed line), except when *carcass persistence* was very low (when only 25% of the carcass are available to be found the next day; black color). The figure shows that the confidence around that estimate decreases when the survey *frequency* decreases (more days between surveys). This decrease in the confidence level is greater when *carcass persistence* is low (black color). Thus, a relatively frequent *search interval* is necessary to maintain a relatively small confidence interval around the estimate when *carcass persistence* is low or moderate.

Once *carcass persistence* trials are performed, it is recommended to use the carcass class with the most rapid removal rate (e.g. small birds may have the lowest persistence) to establish survey *frequency*. Higher survey *frequency* typically results in more precise mortality estimates because a higher proportion of carcasses will remain to be found (Fig. 2; Huso et al. 2016a, WEST 2016). Ideally, surveys should take place at regular intervals (e.g. every five days) for the *duration* of the survey period (i.e. the six to eight week seasonal block or throughout the year;

Huso 2010). This is an assumption of some mortality estimator equations, but some estimators allow for irregular intervals which would allow for an adaptive monitoring approach. However, if *searcher efficiency* and *carcass persistence* vary across seasons, survey frequency can be adjusted to each season (Huso 2010).

Monitoring efforts should be spread out in time to be able to capture variation in mortality that could exist due to weather, migratory patterns, etc. and to maximize the likelihood of capturing unusual mortality events (Strickland et al. 2011). For example, if the survey *frequency* is determined to be every five days, a rotation covering 20% of the *sampling fraction* each day until completion would assure temporal coverage of the site. Similarly, sampling 25% of the *sampling fraction* for four consecutive days and taking one day off would also allow to maintain the five-day survey *frequency* while maintaining good temporal coverage. Completion of 100% of the sampling fraction on a single day is possible but increases the likelihood of producing a biased estimate (Kunz et al. 2007a) because large mortality events may be over- or under-sampled (Huso et al. 2016a).

Lastly, if carcasses are found opportunistically outside the survey period but inside a survey area, they should be documented and left in place to be found during the scheduled surveys, removed by scavenger, or neither (Huso et al. 2016a). However, the carcass can be removed and the data collected could still be used later for mortality estimates, if appropriate (Huso et al. 2016a).

Mortality (count)
The number of carcasses detected influences the estimates of actual mortality, and it should be considered as its magnitude can impact the study design. Simulations performed by Korner-Nievergelt et al. (2011) showed that the precision of the mortality estimate was low when there were fewer than 10 carcasses found. This result was corroborated in our simulations (not shown here) and WEST (2016). If solar energy facilities are associated with a low bird mortality rate, and therefore a low number of carcasses are found (which can be exacerbated by low carcass persistence, as may be the case in Florida), a high sampling fraction may be required to maintain the desired level of precision. Since precision decreases considerably as searcher efficiency and carcass persistence decreases (based on our simulations and Korner-Nievergelt et al. 2011), another approach to help compensate for low counts is to increase searcher efficiency and carcass persistence. Dogs may provide the means to increase searcher efficiency (Mathews et al. 2013, Reyes et al. 2016) and some exclusion measures (e.g. fence improvements) may help mitigate carcass removal (albeit, depending on scavenger type this may have a small effect and may be costly). The best approach may include a combination of these factors while also decreasing survey frequency and potentially increasing duration. If a rigorous and conservative monitoring approach is taken (i.e. reasonably high searcher efficiency, high survey frequency, and a large sampling fraction is monitored) and the number of carcasses found is still low, this may indicate that mortality is actually low. To verify that this is evidence of a low mortality rate, analysis designed for this case should be performed (Huso et al. 2015, Dalthorp et al. 2014).

Background mortality

Avian mortality can occur within the solar energy facility independent of the presence of solar energy infrastructure, but in general this background mortality has been poorly studied. Some studies (mostly from the wind energy sector) have used reference plots and have found no

difference in mortality between monitoring and reference plots (e.g. Osborn et al. 2000, H.T. Harvey and Associates 2015), but monitoring was not consistent or balanced. Little work has been done that thoroughly measures background mortality at PV solar energy facilities (WEST 2014). Preliminary evidence from three studies with limited effort suggests that background mortality (e.g. from predation) appears to be a substantial contributor to fatalities found at solar and wind energy facilities (Erickson et al. 2014). However, further studies are needed to determine the contribution of background mortality in a statistically rigorous manner (WEST 2014). An improved and more balanced study comparing a solar energy facility that is currently in development and a control plot (same size, layout, search effort, etc.), found no significant difference in avian mortality between the facility and control plots, and even found slightly higher mortality in control plots (Boroski et al. 2016). Yet, at the time of this report, this site had not yet been commissioned and the solar energy infrastructure had been only partially put in place (Boroski et al. 2016). Future work at this site will help elucidate the importance of background mortality in affecting fatalities at PV facilities in California.

There are important caveats to consider when estimating background mortality rates. First, estimating *background mortality* rates can be very costly. In fact, it may effectively double monitoring costs since a rigorous approach would require estimating *searcher efficiency* and *carcass persistence* rates on the control plots outside of the solar facility. Similarly, monitoring of these control plots would have to follow the same protocol (schedule/area cover) and effort as monitoring within the arrays. Second, finding a control area of similar size and spatial resource distribution as that of the one monitored within the PV array may be difficult because the site should be close to the solar energy facility to be representative of the background mortality of the area, but far away enough from the solar facility to prevent scavengers from transferring carcasses from the solar facility and into control plots. Ideally control and monitoring plots should have similar vegetation structure (e.g. grasslands). Third, background mortality rates may be low. Adult survivorship for birds varies widely across species but is often >50% annually for small, short-lived species (e.g., Karr 1990, Faaborg et al. 1995), greater for larger species (e.g., Stromborg et al 2012, Koczur et al. 2017) and tends to be greater in subtropical and tropical climates such as that in Florida (Ricklefs 1973, Skutch 1985). As such, background mortality monitoring at a control site is likely to detect few or no dead birds unless a substantial number of birds routinely use the site. Together, these factors indicate measuring background mortality rates is costly and, when combined with potentially low mortality rates associated with PV energy facilities, may be of low priority. Yet, when treated as a true replicate of the mortality monitoring within the array (i.e. in a treatment vs. control framework) this option can be informative. Before After Control Impact (BACI) studies offer an alternative approach to measuring background mortality (Hewitt et al. 2001). Yet, a rigorous approach may require a significant temporal increase in the monitoring plan, including start of monitoring before construction of the facility.

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

FORM: 42-1A

JANUARY 2017 THROUGH DECEMBER 2017

	2017
1. Over/(Under) Recovery for the Current Period (Form 42-2A, Line 5)	$59,791,888
2. Interest Provision (Form 42-2A, Line 6)	$578,084
3. Total	$60,369,973
4. Actual/Estimated Over/(Under) Recovery for the Same Period [(a)]	$28,365,707
5. Interest Provision	$431,995
6. Total	$28,797,701
7. Net True-Up for the period Over/(Under)	$31,572,272

[(a)] Approved in Order No. PSC-2018-0014-FOF-EI issued on January 5, 2018□

Note: Totals may not add due to rounding

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 11
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Renae B. Deaton RBD-1

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

FORM: 42-2A

JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1. ECRC Revenues (net of Revenue Taxes)	$19,020,904	$16,158,964	$17,092,622	$18,716,891	$21,244,550	$23,622,657	$24,983,373	$24,781,611	$23,728,803	$22,522,607	$18,989,331	$18,243,961	$249,106,274
2. True-up Provision	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$11,392,170
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$19,970,251	$17,108,312	$18,041,970	$19,666,238	$22,193,897	$24,572,004	$25,932,720	$25,730,959	$24,678,151	$23,471,955	$19,938,679	$19,193,308	$260,498,444
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5A, Line 9)	$1,801,543	$2,530,350	$2,348,467	$2,515,814	$2,669,478	$3,246,176	$3,456,368	$3,283,451	$2,266,734	$3,296,207	$3,212,958	$3,127,332	$33,754,880
b. Capital Investment Projects (Form 42-7A, Line 9)	$14,022,596	$14,001,320	$13,978,047	$13,954,361	$13,929,761	$13,906,445	$13,881,632	$13,860,207	$13,844,510	$13,843,210	$13,845,786	$13,883,802	$166,951,676
c. Total Jurisdictional ECRC Costs	$15,824,140	$16,531,670	$16,326,514	$16,470,175	$16,599,239	$17,152,621	$17,338,000	$17,143,658	$16,111,244	$17,139,417	$17,058,743	$17,011,134	$200,706,556
5. Over/(Under) Recovery (Line 3 - Line 4c)	$4,146,112	$576,642	$1,715,456	$3,196,063	$5,594,658	$7,419,383	$8,594,720	$8,587,301	$8,566,907	$6,332,538	$2,879,935	$2,182,174	$59,791,888
6. Interest Provision (Form 42-3A, Line 10)	$22,425	$22,021	$25,356	$30,036	$32,824	$41,543	$51,529	$58,049	$53,396	$60,889	$81,523	$98,493	$578,084
7. Prior Periods True-Up to be (Collected)/Refunded	$11,392,170	$14,611,359	$14,260,674	$15,052,139	$17,328,891	$22,007,026	$28,518,604	$36,215,506	$43,911,508	$51,582,464	$57,026,543	$59,038,653	$11,392,170
a. Deferred True-Up (Form 42-1A, Line 7)[a]	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	
8. True-Up Collected /(Refunded) (See Line 2)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($11,392,170)
9. End of Period True-Up (Lines 5+6+7+7a+8)	$38,483,740	$38,133,055	$38,924,520	$41,201,272	$45,879,407	$52,390,985	$60,087,887	$67,783,889	$75,454,844	$80,898,924	$82,911,034	$84,242,353	$60,369,973
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)	$38,483,740	$38,133,055	$38,924,520	$41,201,272	$45,879,407	$52,390,985	$60,087,887	$67,783,889	$75,454,844	$80,898,924	$82,911,034	$84,242,353	$60,369,973

[a] From FPL's 2016 Final True-up filed on April 3, 2017.

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

FORM: 42-3A

JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1. Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$35,264,551	$38,483,740	$38,133,055	$38,924,520	$41,201,272	$45,879,407	$52,390,985	$60,087,887	$67,783,889	$75,454,844	$80,898,924	$82,911,034	N/A
2. Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	$38,461,315	$38,111,034	$38,899,163	$41,171,236	$45,846,582	$52,349,442	$60,036,357	$67,725,840	$75,401,448	$80,838,034	$82,829,511	$84,143,861	N/A
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$73,725,866	$76,594,774	$77,032,219	$80,095,756	$87,047,854	$98,228,849	$112,427,342	$127,813,727	$143,185,337	$156,292,879	$163,728,435	$167,054,895	N/A
4. Average True-Up Amount (Line 3 x 1/2)	$36,862,933	$38,297,387	$38,516,109	$40,047,878	$43,523,927	$49,114,425	$56,213,671	$63,906,863	$71,592,668	$78,146,439	$81,864,217	$83,527,448	N/A
5. Interest Rate (First Day of Reporting Month)	0.72000%	0.74000%	0.64000%	0.94000%	0.86000%	0.95000%	1.08000%	1.12000%	1.06000%	0.73000%	1.14000%	1.25000%	N/A
6. Interest Rate (First Day of Subsequent Month)	0.74000%	0.64000%	0.94000%	0.86000%	0.95000%	1.08000%	1.12000%	1.06000%	0.73000%	1.14000%	1.25000%	1.58000%	N/A
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	1.46000%	1.38000%	1.58000%	1.80000%	1.81000%	2.03000%	2.20000%	2.18000%	1.79000%	1.87000%	2.39000%	2.83000%	N/A
8. Average Interest Rate (Line 7 x 1/2)	0.73000%	0.69000%	0.79000%	0.90000%	0.90500%	1.01500%	1.10000%	1.09000%	0.89500%	0.93500%	1.19500%	1.41500%	N/A
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.06083%	0.05750%	0.06583%	0.07500%	0.07542%	0.08458%	0.09167%	0.09083%	0.07458%	0.07792%	0.09958%	0.11792%	N/A
10. Interest Provision for the Month (Line 4 x Line 9)	$22,425	$22,021	$25,356	$30,036	$32,824	$41,543	$51,529	$58,049	$53,396	$60,889	$81,523	$98,493	$578,084

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

JANUARY 2017 THROUGH DECEMBER 2017
VARIANCE REPORT OF O&M ACTIVITES

(1)	(2)	(3)	(4)	(5)
O&M Projects	ECRC - 2017 Final True-Up [a]	ECRC - 2017 Actual/Estimated [b]	Dif. ECRC - 2017 Actual/Estimated [c]	% Dif. ECRC - 2017 Actual/Estimated [d]
1 - Air Operating Permit Fees	$382,458	$342,223	$40,235	11.8%
3a - Continuous Emission Monitoring Systems	$419,613	$419,642	($29)	(0.0%)
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,937,349	$1,615,250	$322,098	19.9%
8a - Oil Spill Clean-up/Response Equipment	$262,890	$249,543	$13,347	5.3%
NA-Amortization of Gains on Sales of Emissions Allowances	($123,492)	($4,274)	($119,218)	2,789.1%
14 - NPDES Permit Fees	$69,200	$74,435	($5,235)	(7.0%)
17a - Disposal of Non-Containerized Liquid Waste	($13,821)	$5,000	($18,821)	(376.4%)
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$2,063,849	$2,751,121	($687,272)	(25.0%)
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$901,320	$1,021,093	($119,773)	(11.7%)
21 - St. Lucie Turtle Nets	$163,228	$110,000	$53,228	48.4%
22 - Pipeline Integrity Management	$171,592	$401,500	($229,908)	(57.3%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$831,037	$920,034	($88,997)	(9.7%)
24 - Manatee Reburn	$237,869	$341,784	($103,915)	(30.4%)
27 - Lowest Quality Water Source	$134,714	$149,831	($15,116)	(10.1%)
28 - CWA 316(b) Phase II Rule	$1,166,528	$1,163,160	$3,367	0.3%
29 - SCR Consumables	$383,767	$700,469	($316,702)	(45.2%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$4,220,907	$4,121,591	$99,316	2.4%
33 - MATS Project	$1,835,382	$2,050,981	($215,598)	(10.5%)
35 - Martin Plant Drinking Water System Compliance	$39,316	$50,000	($10,684)	(21.4%)
37 - DeSoto Next Generation Solar Energy Center	$520,796	$723,025	($202,229)	(28.0%)
38 - Space Coast Next Generation Solar Energy Center	$200,413	$249,245	($48,832)	(19.6%)
39 - Martin Next Generation Solar Energy Center	$5,197,449	$3,804,619	$1,392,830	36.6%
41 - Manatee Temporary Heating System	$2,004,557	$2,375,922	($371,365)	(15.6%)
42 - Turkey Point Cooling Canal Monitoring Plan	$11,150,044	$37,649,926	($26,499,882)	(70.4%)
45 - 800 MW Unit ESP	$631,002	$746,628	($115,626)	(15.5%)
47 - NPDES Permit Renewal Requirements	$189,569	$122,677	$66,892	54.5%
48 - Industrial Boiler MACT	$76,538	$38,000	$38,538	101.4%
50 - Steam Electric Effluent Guidelines Revised Rules	$363,379	$164,576	$198,803	120.8%
51 - Gopher Tortoise Relocations	$19,514	$39,000	($19,486)	(50.0%)
52 - Numeric Nutrient Criteria Water Quality Standards in Florida	$4,368	$4,368	$0	(0.0%)
54 - Coal Combustion Residuals	$0	$9,600	($9,600)	(100.0%)
Total	$35,441,333	$62,410,969	($26,969,636)	(43.21%)

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

[b] The approved projected amount in accordance with FPSC Order No. PSC-2018-0014-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

JANUARY 2017 THROUGH DECEMBER 2017

VARIANCE REPORT OF O&M ACTIVITES

(1)	(2)	(3)	(4)	(5)
	ECRC - 2017 Final True-Up	ECRC - 2017 Estimated/Actual Filing	Dif. ECRC - 2017 Estimated/Actual Filing	% Dif. ECRC - 2017 Estimated/Actual Filing
2. Total of O&M Activities	$35,441,333	$62,410,969	($26,969,636)	(43.2%)
3. Recoverable Costs Allocated to Energy	$21,391,175	$48,999,435	($27,608,260)	(56.3%)
4a. Recoverable Costs Allocated to CP Demand	$11,986,309	$10,660,413	$1,325,896	12.4%
4b. Recoverable Costs Allocated to GCP Demand	$2,063,849	$2,751,121	($687,272)	(25.0%)
7. Jurisdictional Energy Recoverable Costs	$20,298,454	$46,496,407	($26,197,953)	(56.3%)
8a. Jurisdictional CP Demand Recoverable Costs	$11,392,577	$10,132,358	$1,260,219	12.4%
8b. Jurisdictional GCP Demand Recoverable Costs	$2,063,849	$2,751,121	($687,272)	(25.0%)
9. Total Jurisdictional Recoverable Costs for O&M Activities	$33,754,880	$59,379,886	($25,625,006)	(43.2%)

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

JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
O&M Projects	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
1 - Air Operating Permit Fees	$9,485	$25,096	$67,825	$25,096	$26,177	$26,177	$26,177	$26,721	$26,177	$35,561	$43,982	$43,982	$382,458
3a - Continuous Emission Monitoring Systems	$37,685	$28,998	$37,794	$22,196	$19,871	$17,562	$28,949	$18,772	$38,598	$23,364	$65,080	$80,746	$419,613
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	$16,831	$132,184	$71,568	$285,581	$329,168	$382,063	$8,695	$51,913	$1,441	$164,960	$184,622	$308,324	$1,937,349
8a - Oil Spill Clean-up/Response Equipment	$15,351	$13,950	$12,397	$12,872	$10,233	$43,345	$13,724	$7,023	$10,966	$5,861	$45,500	$71,667	$262,890
14 - NPDES Permit Fees	$69,200	$0	$5,235	$0	$0	$0	$0	$0	$0	$3,600	$0	($8,835)	$69,200
17a - Disposal of Non-Containerized Liquid Waste	$0	$0	$0	$0	$0	$0	$179	($14,000)	$0	$0	$0	$0	($13,821)
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$55,094	$61,635	$210,024	$180,754	$289,287	$269,384	$165,748	$139,709	$168,405	$105,769	$176,703	$241,338	$2,063,849
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$18,563	$53,336	$41,468	$278,043	$63,918	$79,995	$21,272	$30,417	$71,812	$29,660	$27,533	$185,301	$901,320
21 - St. Lucie Turtle Nets	$0	$0	$0	$0	$0	$39,058	$12,965	$13,815	$47,919	$22,496	$13,815	$13,159	$163,228
NA-Amortization of Gains on Sales of Emissions Allowances	($347)	($347)	($347)	($347)	($361)	($361)	($361)	($374)	($367)	($367)	($367)	($119,547)	($123,492)
22 - Pipeline Integrity Management	$0	$17,905	$189	$0	$997	$176	$0	$0	$0	$50	$134,271	$18,004	$171,592
23 - SPCC - Spill Prevention, Control & Countermeasures	$56,158	$75,834	$93,234	$101,375	$114,909	$21,586	$118,901	$128,528	$89,141	($57,008)	$56,483	$31,897	$831,037
24 - Manatee Reburn	$20,249	$25,790	$6,754	$4,537	$13,489	$835	$27,795	$0	$22,522	$5,158	$0	$110,741	$237,869
27 - Lowest Quality Water Source	$10,623	$12,141	$11,710	$11,046	$12,070	$11,226	$11,074	$10,880	$10,925	$11,047	$10,899	$11,075	$134,714
28 - CWA 316(b) Phase II Rule	($5,374)	$89,956	$107,796	$136,924	$102,989	$157,008	$37,440	$140,537	$112,902	$92,899	$98,912	$94,538	$1,166,528
29 - SCR Consumables	$16,463	$23,215	$62,633	$10,939	$24,480	$60,168	$50,197	$29,815	$41,922	$21,781	$15,784	$26,368	$383,767
31 - Clean Air Interstate Rule (CAIR) Compliance	$388,814	$413,509	$197,052	$317,977	$345,970	$391,011	$437,525	$362,557	$284,288	$329,274	$375,505	$377,425	$4,220,907
33 - MATS Project	$31,065	$88,713	$243,346	$140,448	$112,657	$169,203	$172,733	$219,470	$221,799	$108,908	$119,543	$207,497	$1,835,382
35 - Martin Plant Drinking Water System Compliance	$7,498	$135	$250	$7,843	$6,075	$2,500	$3,359	$420	$8,461	$53	$90	$2,633	$39,316
37 - DeSoto Next Generation Solar Energy Center	$36,685	$69,101	$41,035	$32,914	$100,216	$34,674	$28,317	$48,479	$21,617	$37,319	$26,999	$43,440	$520,796
38 - Space Coast Next Generation Solar Energy Center	$8,428	$17,888	$11,065	$8,555	$8,594	$6,982	$19,961	$26,549	$10,880	$35,970	$18,569	$26,972	$200,413
39 - Martin Next Generation Solar Energy Center	$406,187	$407,297	$390,803	$214,141	$247,497	$523,880	$867,537	$418,049	$218,439	$365,331	$470,721	$667,568	$5,197,449
41 - Manatee Temporary Heating System	$1,274	$15,154	$45,062	$10,923	$230,066	$199,496	$408,999	$417,557	$239,891	$236,334	$181,835	$17,965	$2,004,557
42 - Turkey Point Cooling Canal Monitoring Plan	$574,833	$867,533	$730,260	$722,895	$662,082	$918,451	$1,102,614	$1,285,626	$614,557	$1,782,810	$1,162,512	$725,873	$11,150,044
45 - 800 MW Unit ESP	$61,598	$140,176	$84,115	$81,545	$47,763	$36,766	$30,383	$28,732	$27,592	$30,137	$24,635	$37,561	$631,002
47 - NPDES Permit Renewal Requirements	($1,052)	$1	$0	$18,558	$3,301	$0	$10,412	$21,614	$44,322	$25,656	$38,918	$27,839	$189,569
48 - Industrial Boiler MACT	$0	$0	$0	$0	$0	$0	$0	$0	$10,763	$21,232	$25,325	$19,217	$76,538
50 - Steam Electric Effluent Guidelines Revised Rules	$59,135	$82,486	($13,301)	$14,891	$24,505	$13,165	$27,011	$31,769	$20,685	$28,827	$56,640	$17,566	$363,379
51 - Gopher Tortoise Relocations	$0	$0	$0	$0	$0	$0	$0	$6,594	$12,920	$0	$0	$0	$19,514
52 - Numeric Nutrient Criteria Water Quality Standards in Florida	$0	$0	$4,368	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,368
54 - Coal Combustion Residuals	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total of O&M Activities	$1,894,445	$2,661,684	$2,462,337	$2,639,706	$2,795,955	$3,404,349	$3,631,607	$3,451,170	$2,378,579	$3,466,681	$3,374,508	$3,280,313	$35,441,333

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

FORM: 42-5A

JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)
Method of Classification	Total	Energy	CP Demand	GCP Demand
1 - Air Operating Permit Fees	$382,458	$382,458	$0	$0
3a - Continuous Emission Monitoring Systems	$419,613	$419,613	$0	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,937,349	$0	$1,937,349	$0
8a - Oil Spill Clean-up/Response Equipment	$262,890	$262,890	$0	$0
14 - NPDES Permit Fees	$69,200	$0	$69,200	$0
17a - Disposal of Non-Containerized Liquid Waste	($13,821)	($13,821)	$0	$0
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$2,063,849	$0	$0	$2,063,849
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$901,320	$0	$901,320	$0
21 - St. Lucie Turtle Nets	$163,228	$0	$163,228	$0
NA-Amortization of Gains on Sales of Emissions Allowances	($123,492)	($123,492)	$0	$0
22 - Pipeline Integrity Management	$171,592	$0	$171,592	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	$831,037	$0	$831,037	$0
24 - Manatee Reburn	$237,869	$237,869	$0	$0
27 - Lowest Quality Water Source	$134,714	$0	$134,714	$0
28 - CWA 316(b) Phase II Rule	$1,166,528	$0	$1,166,528	$0
29 - SCR Consumables	$383,767	$383,767	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	$4,220,907	$4,220,907	$0	$0
33 - MATS Project	$1,835,382	$1,835,382	$0	$0
35 - Martin Plant Drinking Water System Compliance	$39,316	$0	$39,316	$0
37 - DeSoto Next Generation Solar Energy Center	$520,796	$0	$520,796	$0
38 - Space Coast Next Generation Solar Energy Center	$200,413	$0	$200,413	$0
39 - Martin Next Generation Solar Energy Center	$5,197,449	$0	$5,197,449	$0
41 - Manatee Temporary Heating System	$2,004,557	$2,004,557	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	$11,150,044	$11,150,044	$0	$0
45 - 800 MW Unit ESP	$631,002	$631,002	$0	$0
47 - NPDES Permit Renewal Requirements	$189,569	$0	$189,569	$0
48 - Industrial Boiler MACT	$76,538	$0	$76,538	$0
50 - Steam Electric Effluent Guidelines Revised Rules	$363,379	$0	$363,379	$0
51 - Gopher Tortoise Relocations	$19,514	$0	$19,514	$0
52 - Numeric Nutrient Criteria Water Quality Standards in Florida	$4,368	$0	$4,368	$0
54 - Coal Combustion Residuals	$0	$0	$0	N/A
Total of O&M Activities	$35,441,333	$21,391,175	$11,986,309	$2,063,849

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

FORM: 42-5A

JANUARY 2017 THROUGH DECEMBER 2017
O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
2. Total of O&M Activities	$1,894,445	$2,661,684	$2,462,337	$2,639,706	$2,795,955	$3,404,349	$3,631,607	$3,451,170	$2,378,579	$3,466,681	$3,374,508	$3,280,313	$35,441,333
3. Recoverable Costs Allocated to Energy	$1,156,471	$1,641,787	$1,486,893	$1,349,080	$1,492,428	$1,862,652	$2,298,914	$2,381,897	$1,527,947	$2,578,821	$2,034,009	$1,580,277	$21,391,175
4a. Recoverable Costs Allocated to CP Demand	$682,881	$958,263	$765,420	$1,109,871	$1,014,240	$1,272,313	$1,166,945	$929,564	$682,227	$782,091	$1,163,797	$1,458,698	$11,986,309
4b. Recoverable Costs Allocated to GCP Demand	$55,094	$61,635	$210,024	$180,754	$289,287	$269,384	$165,748	$139,709	$168,405	$105,769	$176,703	$241,338	$2,063,849
5.Retail Energy Jurisdictional Factor	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	
6a. Retail CP Demand Jurisdictional Factor	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	
6b. Retail GCP Demand Jurisdictional	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 Energy Recoverable Costs [a]	$1,097,395	$1,557,920	$1,410,938	$1,280,165	$1,416,191	$1,767,502	$2,181,479	$2,260,223	$1,449,895	$2,447,087	$1,930,106	$1,499,552	$20,298,454
8a. Jurisdictional CP Demand Recoverable Costs [b]	$649,055	$910,796	$727,506	$1,054,895	$964,000	$1,209,290	$1,109,141	$883,519	$648,434	$743,351	$1,106,149	$1,386,443	$11,392,577
8b. Jurisdictional GCP Demand Recoverable Costs [c]	$55,094	$61,635	$210,024	$180,754	$289,287	$269,384	$165,748	$139,709	$168,405	$105,769	$176,703	$241,338	$2,063,849
9. Total Jurisdictional Recoverable Costs for O&M Activities [d]	$1,801,543	$2,530,350	$2,348,467	$2,515,814	$2,669,478	$3,246,176	$3,456,368	$3,283,451	$2,266,734	$3,296,207	$3,212,958	$3,127,332	$33,754,880

[a] Line 3 x 5
[b] Line 4a x Line 6a
[c] Line 4b x Line 6b
[d] Line 7 + Line 8a + 8b

Docket No. 20180007-EI
2017 ECRC Final True Up Calculation
Exhibit RBD-1, Page 8 of 47

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

JANUARY 2017 THROUGH DECEMBER 2017
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
Capital Projects	ECRC - 2017 Final True-Up [a]	ECRC - 2017 Actual/Estimated Filing [b]	Dif. ECRC - 2017 Actual/Estimated Filing [c]	% Dif. ECRC - 2017 Actual/Estimated Filing [d]
2 - Low NOX Burner Technology	$70,450	$70,450	$0	(0.0%)
3 - Continuous Emission Monitoring Systems	$590,622	$601,145	($10,524)	(1.8%)
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,816,788	$1,791,982	$24,806	1.4%
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,965	$1,965	$0	(0.0%)
8 - Oil Spill Clean-up/Response Equipment	$183,044	$176,138	$6,906	3.9%
10 - Relocate Storm Water Runoff	$7,496	$7,496	$0	(0.0%)
NA-Amortization of Gains on Sales of Emissions Allowances	($278)	($278)	$0	(0.0%)
12 - Scherer Discharge Pipeline	$40,814	$40,814	$0	(0.0%)
20 - Wastewater Discharge Elimination & Reuse	$88,952	$88,952	$0	(0.0%)
21 - St. Lucie Turtle Nets	$866,986	$866,986	$0	(0.0%)
22 - Pipeline Integrity Management	$313,316	$314,809	($1,493)	(0.5%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$2,216,938	$2,291,013	($74,075)	(3.2%)
24 - Manatee Reburn	$3,591,326	$3,591,327	($1)	(0.0%)
26 - UST Remove/Replacement	$7,888	$7,888	$0	(0.0%)
28 - CWA 316(b) Phase II Rule	$49,632	$72,282	($22,650)	(31.3%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$57,196,003	$57,230,796	($34,793)	(0.1%)
33 - MATS Project	$11,048,537	$11,048,537	$0	0.0%
34 - St Lucie Cooling Water System Inspection & Maintenance	$410,206	$408,341	$1,865	0.5%
35 - Martin Plant Drinking Water System Compliance	$23,796	$23,796	$0	(0.0%)
36 - Low-Level Radioactive Waste Storage	$1,966,477	$1,966,477	$0	(0.0%)
37 - DeSoto Next Generation Solar Energy Center	$14,988,059	$14,987,903	$157	0.0%
38 - Space Coast Next Generation Solar Energy Center	$6,960,615	$6,961,171	($556)	(0.0%)
39 - Martin Next Generation Solar Energy Center	$41,764,837	$41,784,040	($19,203)	(0.0%)
41 - Manatee Temporary Heating System	$38,309	$36,320	$1,989	5.5%
42 - Turkey Point Cooling Canal Monitoring Plan	$3,042,331	$3,538,078	($495,747)	(14.0%)
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$17,363	$17,363	$0	(0.0%)
45 - 800 MW Unit ESP	$27,680,644	$27,680,544	$100	0.0%
54 - Coal Combustion Residuals	$694,299	$937,265	($242,966)	(25.9%)
Total	$175,677,417	$176,543,602	$866,185	(0.5%)

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

FORM: 42-6A

JANUARY 2017 THROUGH DECEMBER 2017
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
	ECRC - 2017 Final True-Up	ECRC - 2017 Actual/Estimated Filing	Dif. ECRC - 2017 Actual/Estimated Filing	% Dif. ECRC - 2017 Actual/Estimated Filing
2. Total Investment Projects - Recoverable Costs	$175,677,417	$176,543,602	($866,185)	(0.49%)
3. Recoverable Costs Allocated to Energy	$15,304,248	$15,384,417	($80,170)	(0.52%)
4. Recoverable Costs Allocated to Demand	$160,373,169	$161,159,185	($786,016)	(0.49%)
7. Jurisdictional Energy Recoverable Costs	$14,522,464	$14,598,538	($76,074)	(0.52%)
8. Jurisdictional Demand Recoverable Costs	$152,429,213	$153,176,294	($747,081)	(0.49%)
9. Total Jurisdictional Recoverable Costs for Investment Projects	$166,951,676	$167,774,832	($823,156)	(0.49%)

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

FORM: 42-7A

JANUARY 2017 THROUGH DECEMBER 2017
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Capital Investment Projects	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Twelve Month Amount
2 - Low NOX Burner Technology	$6,006	$5,982	$5,958	$5,934	$5,910	$5,885	$5,856	$5,832	$5,808	$5,784	$5,760	$5,736	$70,450
3 - Continuous Emission Monitoring Systems	$45,773	$46,320	$47,170	$47,340	$47,202	$47,339	$48,734	$51,164	$52,825	$52,918	$51,976	$51,860	$590,622
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$151,710	$151,311	$150,882	$150,463	$150,049	$149,676	$149,582	$149,770	$151,322	$153,688	$154,241	$154,094	$1,816,788
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$169	$168	$167	$166	$165	$164	$163	$162	$161	$160	$159	$158	$1,965
8 - Oil Spill Clean-up/Response Equipment	$15,281	$15,599	$15,690	$15,787	$15,694	$15,286	$15,027	$15,014	$14,943	$14,889	$14,819	$15,015	$183,044
10 - Relocate Storm Water Runoff	$634	$633	$631	$629	$628	$626	$623	$622	$620	$618	$617	$615	$7,496
NA-Amortization of Gains on Sales of Emissions Allowances	($37)	($35)	($32)	($30)	($28)	($25)	($22)	($19)	($17)	($14)	($11)	($8)	($278)
12 - Scherer Discharge Pipeline	$3,457	$3,447	$3,437	$3,428	$3,418	$3,408	$3,394	$3,384	$3,375	$3,365	$3,355	$3,345	$40,814
20 - Wastewater Discharge Elimination & Reuse	$7,541	$7,519	$7,496	$7,474	$7,451	$7,428	$7,397	$7,374	$7,352	$7,329	$7,307	$7,284	$88,952
21 - St. Lucie Turtle Nets	$72,853	$72,753	$72,654	$72,554	$72,455	$72,355	$72,142	$72,043	$71,943	$71,844	$71,745	$71,645	$866,986
22 - Pipeline Integrity Management	$26,397	$26,348	$26,299	$26,251	$26,202	$26,153	$26,066	$26,017	$25,969	$25,920	$25,871	$25,822	$313,316
23 - SPCC - Spill Prevention, Control & Countermeasures	$186,272	$185,889	$186,115	$185,814	$184,766	$184,484	$184,584	$184,461	$183,763	$183,332	$182,965	$184,493	$2,216,938
24 - Manatee Reburn	$304,786	$303,814	$302,842	$301,871	$300,899	$299,927	$298,623	$297,653	$296,683	$295,713	$294,743	$293,772	$3,591,326
26 - UST Remove/Replacement	$664	$663	$662	$661	$659	$658	$656	$655	$654	$653	$652	$651	$7,888
28 - CWA 316(b) Phase II Rule	$2,680	$2,743	$2,772	$2,807	$3,052	$3,316	$3,397	$3,878	$4,553	$5,799	$7,129	$7,507	$49,632
31 - Clean Air Interstate Rule (CAIR) Compliance	$4,827,639	$4,817,689	$4,807,571	$4,797,458	$4,787,294	$4,777,289	$4,760,691	$4,746,615	$4,733,471	$4,723,447	$4,713,393	$4,703,445	$57,196,003
33 - MATS Project	$931,925	$930,002	$928,081	$926,158	$924,235	$922,313	$919,101	$917,182	$915,263	$913,344	$911,426	$909,507	$11,048,537
34 - St Lucie Cooling Water System Inspection & Maintenance	$33,939	$33,969	$33,998	$34,046	$34,089	$34,140	$34,153	$34,242	$34,330	$34,400	$34,439	$34,461	$410,206
35 - Martin Plant Drinking Water System Compliance	$2,005	$2,001	$1,998	$1,994	$1,990	$1,986	$1,980	$1,976	$1,972	$1,968	$1,964	$1,961	$23,796
36 - Low-Level Radioactive Waste Storage	$165,679	$165,372	$165,065	$164,759	$164,452	$164,145	$163,600	$163,293	$162,987	$162,681	$162,375	$162,069	$1,966,477
37 - DeSoto Next Generation Solar Energy Center	$1,268,885	$1,264,922	$1,261,055	$1,257,118	$1,253,272	$1,249,551	$1,248,072	$1,244,338	$1,240,603	$1,236,852	$1,233,101	$1,230,291	$14,988,059
38 - Space Coast Next Generation Solar Energy Center	$589,137	$587,465	$585,749	$584,033	$582,142	$580,252	$579,480	$577,810	$576,141	$574,472	$572,802	$571,133	$6,960,615
39 - Martin Next Generation Solar Energy Center	$3,511,653	$3,509,697	$3,504,173	$3,496,369	$3,490,284	$3,484,643	$3,482,459	$3,472,949	$3,464,457	$3,456,022	$3,449,186	$3,442,943	$41,764,837
41 - Manatee Temporary Heating System	$2,121	$2,527	$2,115	$2,113	$2,112	$2,033	$2,022	$2,230	$2,367	$4,135	$6,081	$8,452	$38,309
42 - Turkey Point Cooling Canal Monitoring Plan	$225,721	$226,186	$230,047	$234,984	$237,754	$240,298	$244,184	$251,870	$262,188	$279,766	$298,754	$310,579	$3,042,331
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$1,463	$1,460	$1,457	$1,455	$1,452	$1,449	$1,445	$1,442	$1,439	$1,437	$1,434	$1,431	$17,363
45 - 800 MW Unit ESP	$2,342,719	$2,336,526	$2,330,211	$2,324,018	$2,317,787	$2,311,375	$2,302,171	$2,295,821	$2,289,471	$2,283,121	$2,276,772	$2,270,653	$27,680,644
54 - Coal Combustion Residuals	$28,415	$32,126	$34,343	$38,031	$42,415	$47,109	$51,576	$56,835	$63,456	$73,085	$86,383	$140,526	$694,299
Total	$14,755,485	$14,733,097	$14,708,609	$14,683,685	$14,657,799	$14,633,264	$14,607,156	$14,584,614	$14,568,099	$14,566,730	$14,569,438	$14,609,440	$175,677,417

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

JANUARY 2017 THROUGH DECEMBER 2017
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

(1)	(2)	(3)	(4)
Method of Classification	Total	CP Demand	Energy
2 - Low NOX Burner Technology	$70,450	$0	$70,450
3 - Continuous Emission Monitoring Systems	$590,622	$0	$590,622
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,816,788	$1,677,035	$139,753
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,965	$1,814	$151
8 - Oil Spill Clean-up/Response Equipment	$183,044	$168,964	$14,080
10 - Relocate Storm Water Runoff	$7,496	$6,920	$577
NA-Amortization of Gains on Sales of Emissions Allowances	($278)	$0	($278)
12 - Scherer Discharge Pipeline	$40,814	$37,675	$3,140
20 - Wastewater Discharge Elimination & Reuse	$88,952	$82,110	$6,842
21 - St. Lucie Turtle Nets	$866,986	$800,295	$66,691
22 - Pipeline Integrity Management	$313,316	$289,215	$24,101
23 - SPCC - Spill Prevention, Control & Countermeasures	$2,216,938	$2,046,404	$170,534
24 - Manatee Reburn	$3,591,326	$0	$3,591,326
25 - Pt. Everglades ESP Technology	$0	$0	$0
26 - UST Remove/Replacement	$7,888	$7,281	$607
28 - CWA 316(b) Phase II Rule	$49,632	$49,632	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	$57,196,003	$52,796,310	$4,399,693
33 - MATS Project	$11,048,537	$10,198,649	$849,887
34 - St Lucie Cooling Water System Inspection & Maintenance	$410,206	$378,652	$31,554
35 - Martin Plant Drinking Water System Compliance	$23,796	$21,965	$1,830
36 - Low-Level Radioactive Waste Storage	$1,966,477	$1,815,209	$151,267
37 - DeSoto Next Generation Solar Energy Center	$14,988,059	$13,835,132	$1,152,928
38 - Space Coast Next Generation Solar Energy Center	$6,960,615	$6,425,183	$535,432
39 - Martin Next Generation Solar Energy Center	$41,764,837	$38,552,157	$3,212,680
41 - Manatee Temporary Heating System	$38,309	$35,362	$2,947
42 - Turkey Point Cooling Canal Monitoring Plan	$3,042,331	$2,808,306	$234,025
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$17,363	$17,363	$0
45 - 800 MW Unit ESP	$27,680,644	$27,680,644	$0
54 - Coal Combustion Residuals	$694,299	$640,891	$53,408
Total	$175,677,417	$160,373,169	$15,304,248

Each project's Total System 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 2017 THROUGH DECEMBER 2017
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Twelve Month Amount
2. Total Investment Projects - Recoverable Costs	14,755,485	14,733,097	14,708,609	14,683,685	14,657,799	14,633,264	14,607,156	14,584,614	14,568,099	14,566,730	14,569,438	14,609,440	175,677,417
3. Recoverable Costs Allocated to Energy	1,283,612	1,281,949	1,280,417	1,278,214	1,275,638	1,273,434	1,272,188	1,272,233	1,272,017	1,271,477	1,270,286	1,272,782	15,304,248
4. Recoverable Costs Allocated to Demand	13,471,873	13,451,148	13,428,191	13,405,471	13,382,161	13,359,830	13,334,968	13,312,381	13,296,082	13,295,254	13,299,152	13,336,658	160,373,169
5.Retail Energy Jurisdictional Factor	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	
6. Retail Demand Jurisdictional Factor	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	
7. Jurisdictional Energy Recoverable Costs [a]	1,218,042	1,216,464	1,215,010	1,212,919	1,210,475	1,208,384	1,207,201	1,207,244	1,207,039	1,206,526	1,205,397	1,207,765	14,522,464
8. Jurisdictional Demand Recoverable Costs [b]	12,804,555	12,784,856	12,763,037	12,741,441	12,719,286	12,698,062	12,674,431	12,652,963	12,637,471	12,636,684	12,640,389	12,676,037	152,429,213
9. Total Jurisdictional Recoverable Costs for Investment Projects	14,022,596	14,001,320	13,978,047	13,954,361	13,929,761	13,906,445	13,881,632	13,860,207	13,844,510	13,843,210	13,845,786	13,883,802	166,951,676

[a] Line 3 x Line 5
[b] Line 4 x Line 6

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

FORM: 42-8A

JANUARY 2017 THROUGH DECEMBER 2017

02 - Low NOX Burner Technology	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$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	
3a. Less: Accumulated Depreciation	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
3b. Less: Capital Recovery Unamortized Balance	($375,828)	($372,696)	($369,564)	($366,432)	($363,300)	($360,168)	($357,036)	($353,904)	($350,772)	($347,640)	($344,509)	($341,377)	($338,245)	
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$375,828	$372,696	$369,564	$366,432	$363,300	$360,168	$357,036	$353,905	$350,773	$347,641	$344,509	$341,377	$338,245	
6. Average Net Investment		$374,262	$371,130	$367,998	$364,866	$361,734	$358,602	$355,471	$352,339	$349,207	$346,075	$342,943	$339,811	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,438	$2,417	$2,397	$2,376	$2,356	$2,336	$2,327	$2,306	$2,286	$2,265	$2,245	$2,224	$27,974
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$436	$432	$429	$425	$422	$418	$397	$394	$390	$387	$383	$380	$4,894
8. Investment Expenses														
a. Depreciation [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization [e]		$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$37,583
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$6,006	$5,982	$5,958	$5,934	$5,910	$5,885	$5,856	$5,832	$5,808	$5,784	$5,760	$5,736	$70,450

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□Average Net Investment: See footnotes (b) and (c).

□Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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

FORM: 42-8A

JANUARY 2017 THROUGH DECEMBER 2017

03 - Continuous Emission Monitoring Systems	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$187,673	$79,766	$13,487	$947	$84,080	($68,641)	($122,280)	$136,306	($16,709)	($225,388)	($113,075)	($43,835)
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$255,503	$329,123	$1,591	($269,211)	($350,989)	$165,992	$132,009
c. Retirements	$0	$0	$0	$0	$0	$0	$0	($36,022)	($5,722)	$0	($362,458)	($620,363)	($16,367)	($1,040,932)
d. Other	$0	$0	($4,056)	($1,720)	($290)	($21)	($1,764)	($4,852)	($4,759)	($2,866)	($1,546)	($883)	($1,542)	($24,300)
2. Plant-In Service/Depreciation Base [a]	$5,690,778	$5,690,778	$5,690,778	$5,690,778	$5,690,778	$5,690,778	$5,690,778	$5,946,280	$6,275,404	$6,276,995	$6,007,784	$5,656,795	$5,822,787	
3a. Less: Accumulated Depreciation	$3,576,307	$3,597,587	$3,614,817	$3,634,380	$3,655,372	$3,676,635	$3,696,154	$3,676,996	$3,689,156	$3,709,428	$3,368,023	$2,768,164	$2,771,277	
3b. Less: Capital Recovery Unamortized Balance	($500,741)	($496,568)	($492,395)	($488,222)	($484,050)	($479,877)	($475,704)	($471,531)	($467,358)	($463,185)	($459,013)	($454,840)	($450,667)	
4. CWIP - Non Interest Bearing	$43,835	$43,835	$231,508	$311,274	$324,761	$325,708	$409,788	$341,147	$218,867	$355,173	$338,463	$113,075	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,659,047	$2,633,594	$2,799,864	$2,855,894	$2,844,215	$2,819,728	$2,880,115	$3,081,962	$3,272,472	$3,385,925	$3,437,237	$3,456,545	$3,502,177	
6. Average Net Investment		$2,646,320	$2,716,729	$2,827,879	$2,850,055	$2,831,972	$2,849,921	$2,981,039	$3,177,217	$3,329,199	$3,411,581	$3,446,891	$3,479,361	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$17,236	$17,695	$18,419	$18,563	$18,446	$18,562	$19,514	$20,798	$21,793	$22,332	$22,563	$22,776	$238,698
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$3,084	$3,166	$3,295	$3,321	$3,300	$3,321	$3,332	$3,551	$3,721	$3,813	$3,853	$3,889	$41,648
8. Investment Expenses														
a. Depreciation [d]		$21,280	$21,286	$21,283	$21,283	$21,283	$21,283	$21,715	$22,641	$23,137	$22,600	$21,387	$21,022	$260,201
b. Amortization [e]		$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$50,074
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$45,773	$46,320	$47,170	$47,340	$47,202	$47,339	$48,734	$51,164	$52,825	$52,918	$51,976	$51,860	$590,622

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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05 - Maintenance of Stationary Above Ground Storage Tanks	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$1,103	$10,844	$121,616	($133,563)	$477,768	$249,308	$4,662	$64,230	$795,968
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$133,572	$0	$0	$0	$0	$133,572
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($23)	($28)	$0	($51)
2. Plant-In Service/Depreciation Base [a]	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,527,336	$13,527,336	$13,527,336	$13,527,336	$13,527,336	
3a. Less: Accumulated Depreciation	$3,867,188	$3,895,415	$3,923,662	$3,951,900	$3,980,137	$4,008,374	$4,036,612	$4,064,849	$4,093,226	$4,121,744	$4,150,239	$4,178,729	$4,207,256	
3b. Less: Capital Recovery Unamortized Balance	($3,156,456)	($3,130,152)	($3,103,849)	($3,077,545)	($3,051,241)	($3,024,937)	($2,998,633)	($2,972,330)	($2,946,026)	($2,919,722)	($2,893,418)	($2,867,114)	($2,840,811)	
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$1,103	$11,947	$133,563	$0	$477,768	$727,076	$731,738	$795,968	
5. Net Investment (Lines 2 - 3 + 4)	$12,683,032	$12,628,501	$12,573,950	$12,519,409	$12,464,868	$12,411,430	$12,367,733	$12,434,808	$12,380,135	$12,803,082	$12,997,591	$12,947,459	$12,956,858	
6. Average Net Investment		$12,655,766	$12,601,225	$12,546,679	$12,492,138	$12,438,149	$12,389,581	$12,401,270	$12,407,471	$12,591,608	$12,900,336	$12,972,525	$12,952,159	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$82,431	$82,076	$81,720	$81,365	$81,014	$80,697	$81,179	$81,220	$82,425	$84,446	$84,919	$84,785	$988,277
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$14,748	$14,684	$14,621	$14,557	$14,494	$14,438	$13,862	$13,869	$14,075	$14,420	$14,501	$14,478	$172,746
8. Investment Expenses														
a. Depreciation [d]		$28,228	$28,247	$28,237	$28,237	$28,237	$28,237	$28,237	$28,378	$28,518	$28,518	$28,518	$28,527	$340,120
b. Amortization [e]		$26,304	$26,304	$26,304	$26,304	$26,304	$26,304	$26,304	$26,304	$26,304	$26,304	$26,304	$26,304	$315,646
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$151,710	$151,311	$150,882	$150,463	$150,049	$149,676	$149,582	$149,770	$151,322	$153,688	$154,241	$154,094	$1,816,788

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□Average Net Investment: See footnotes (b) and (c).

□Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$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	$26,112	$26,244	$26,376	$26,508	$26,640	$26,772	$26,905	$27,037	$27,169	$27,301	$27,433	$27,565	$27,697	
3b. Less: Capital Recovery Unamortized Balance	$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)	$4,918	$4,786	$4,654	$4,522	$4,390	$4,258	$4,125	$3,993	$3,861	$3,729	$3,597	$3,465	$3,333	
6. Average Net Investment		$4,852	$4,720	$4,588	$4,456	$4,324	$4,191	$4,059	$3,927	$3,795	$3,663	$3,531	$3,399	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$32	$31	$30	$29	$28	$27	$27	$26	$25	$24	$23	$22	$323
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$6	$6	$5	$5	$5	$5	$5	$4	$4	$4	$4	$4	$57
8. Investment Expenses														
a. Depreciation [d]		$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$1,586
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$169	$168	$167	$166	$165	$164	$163	$162	$161	$160	$159	$158	$1,965

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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08 - Oil Spill Clean-up/Response Equipment	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	Total
1. Investments														
a. Expenditures/Additions	$0	$1,051	$16,400	$20,858	$11,495	$2,831	($13,432)	$0	$0	$0	$181	$0	($1)	$39,382
b. Clearings to Plant	$0	$2,154	$0	$2,638	$2,518	$0	($36,031)	$5,984	($1,254)	$0	$0	($2,743)	$14,850	($11,883)
c. Retirements	$0	$2,154	$0	($5,007)	$0	$0	($40,930)	$0	($1,254)	$0	$0	($2,743)	($31,522)	($79,302)
d. Other	$0	$0	$0	$0	$0	$30,000	$0	$0	$0	$0	$0	$0	$0	$30,000
2. Plant-In Service/Depreciation Base [a]	$949,127	$951,281	$951,281	$953,919	$956,438	$956,438	$920,407	$926,391	$925,137	$925,137	$925,137	$922,395	$937,244	
3a. Less: Accumulated Depreciation	$28,051	$37,376	$44,854	$47,300	$54,745	$92,205	$58,520	$65,586	$71,417	$78,484	$85,551	$89,859	$65,459	
3b. Less: Capital Recovery Unamortized Balance	$220	$218	$216	$214	$212	$211	$209	$207	$205	$203	$201	$200	$198	
4. CWIP - Non Interest Bearing	$138,662	$139,713	$156,113	$176,971	$188,465	$191,296	$177,864	$177,864	$177,864	$177,864	$178,045	$178,045	$178,044	
5. Net Investment (Lines 2 - 3 + 4)	$1,059,518	$1,053,401	$1,062,325	$1,083,375	$1,089,946	$1,055,318	$1,039,542	$1,038,462	$1,031,379	$1,024,314	$1,017,430	$1,010,381	$1,049,631	
6. Average Net Investment		$1,056,459	$1,057,863	$1,072,850	$1,086,661	$1,072,632	$1,047,430	$1,039,002	$1,034,921	$1,027,847	$1,020,872	$1,013,905	$1,030,006	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$6,881	$6,890	$6,988	$7,078	$6,986	$6,822	$6,801	$6,775	$6,728	$6,683	$6,637	$6,742	$82,012
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$1,231	$1,233	$1,250	$1,266	$1,250	$1,221	$1,161	$1,157	$1,149	$1,141	$1,133	$1,151	$14,344
8. Investment Expenses														
a. Depreciation [d]		$7,170	$7,478	$7,454	$7,445	$7,460	$7,245	$7,066	$7,085	$7,067	$7,067	$7,051	$7,123	$86,710
b. Amortization [e]		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($22)
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$15,281	$15,599	$15,690	$15,787	$15,694	$15,286	$15,027	$15,014	$14,943	$14,889	$14,819	$15,015	$183,044

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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10 - Relocate Storm Water Runoff	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	
3a. Less: Accumulated Depreciation	$63,827	$64,048	$64,269	$64,490	$64,711	$64,932	$65,152	$65,373	$65,594	$65,815	$66,036	$66,257	$66,478	
3b. Less: Capital Recovery Unamortized Balance	$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)	$53,967	$53,746	$53,525	$53,304	$53,083	$52,862	$52,641	$52,421	$52,200	$51,979	$51,758	$51,537	$51,316	
6. Average Net Investment		$53,856	$53,635	$53,414	$53,194	$52,973	$52,752	$52,531	$52,310	$52,089	$51,868	$51,648	$51,427	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$351	$349	$348	$346	$345	$344	$344	$342	$341	$340	$338	$337	$4,125
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$63	$63	$62	$62	$62	$61	$59	$58	$58	$58	$58	$57	$721
8. Investment Expenses														
a. Depreciation [d]		$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$2,650
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$634	$633	$631	$629	$628	$626	$623	$622	$620	$618	$617	$615	$7,496

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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12 - Scherer Discharge Pipeline	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$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	$569,216	$570,488	$571,761	$573,033	$574,306	$575,579	$576,851	$578,124	$579,396	$580,669	$581,942	$583,214	$584,487	
3b. Less: Capital Recovery Unamortized Balance	$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)	$285,108	$283,835	$282,563	$281,290	$280,018	$278,745	$277,472	$276,200	$274,927	$273,655	$272,382	$271,109	$269,837	
6. Average Net Investment		$284,472	$283,199	$281,927	$280,654	$279,381	$278,109	$276,836	$275,564	$274,291	$273,018	$271,746	$270,473	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,853	$1,845	$1,836	$1,828	$1,820	$1,811	$1,812	$1,804	$1,796	$1,787	$1,779	$1,771	$21,741
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$331	$330	$329	$327	$326	$324	$309	$308	$307	$305	$304	$302	$3,802
8. Investment Expenses														
a. Depreciation [d]		$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$15,271
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$3,457	$3,447	$3,437	$3,428	$3,418	$3,408	$3,394	$3,384	$3,375	$3,365	$3,355	$3,345	$40,814

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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20 - Wastewater Discharge Elimination & Reuse	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	
3a. Less: Accumulated Depreciation	$172,106	$175,056	$178,005	$180,955	$183,905	$186,855	$189,804	$192,754	$195,704	$198,653	$201,603	$204,553	$207,503	
3b. Less: Capital Recovery Unamortized Balance	$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)	$599,471	$596,521	$593,571	$590,622	$587,672	$584,722	$581,772	$578,823	$575,873	$572,923	$569,974	$567,024	$564,074	
6. Average Net Investment		$597,996	$595,046	$592,096	$589,147	$586,197	$583,247	$580,298	$577,348	$574,398	$571,448	$568,499	$565,549	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][c]		$3,895	$3,876	$3,857	$3,837	$3,818	$3,799	$3,799	$3,779	$3,760	$3,741	$3,721	$3,702	$45,584
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$697	$693	$690	$687	$683	$680	$649	$645	$642	$639	$635	$632	$7,972
8. Investment Expenses														
a. Depreciation [d]		$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$35,397
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$7,541	$7,519	$7,496	$7,474	$7,451	$7,428	$7,397	$7,374	$7,352	$7,329	$7,307	$7,284	$88,952

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□Average Net Investment: See footnotes (b) and (c).

□Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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21 - St. Lucie Turtle Nets	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	
3a. Less: Accumulated Depreciation	($897,472)	($884,516)	($871,561)	($858,605)	($845,650)	($832,695)	($819,739)	($806,784)	($793,828)	($780,873)	($767,917)	($754,962)	($742,007)	
3b. Less: Capital Recovery Unamortized Balance	$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)	$7,807,030	$7,794,075	$7,781,119	$7,768,164	$7,755,209	$7,742,253	$7,729,298	$7,716,342	$7,703,387	$7,690,431	$7,677,476	$7,664,521	$7,651,565	
6. Average Net Investment		$7,800,553	$7,787,597	$7,774,642	$7,761,686	$7,748,731	$7,735,775	$7,722,820	$7,709,865	$7,696,909	$7,683,954	$7,670,998	$7,658,043	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$50,807	$50,723	$50,639	$50,554	$50,470	$50,385	$50,554	$50,469	$50,384	$50,299	$50,215	$50,130	$605,630
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$9,090	$9,075	$9,060	$9,045	$9,030	$9,014	$8,633	$8,618	$8,604	$8,589	$8,575	$8,560	$105,892
8. Investment Expenses														
a. Depreciation [d]		$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$155,465
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$72,853	$72,753	$72,654	$72,554	$72,455	$72,355	$72,142	$72,043	$71,943	$71,844	$71,745	$71,645	$866,986

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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22 - Pipeline Integrity Management	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	
3a. Less: Accumulated Depreciation	$259,949	$266,307	$272,666	$279,024	$285,383	$291,741	$298,100	$304,458	$310,817	$317,175	$323,534	$329,892	$336,251	
3b. Less: Capital Recovery Unamortized Balance														
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,612,843	$2,606,484	$2,600,126	$2,593,767	$2,587,409	$2,581,050	$2,574,692	$2,568,333	$2,561,975	$2,555,616	$2,549,258	$2,542,899	$2,536,541	
6. Average Net Investment		$2,609,663	$2,603,305	$2,596,946	$2,590,588	$2,584,229	$2,577,871	$2,571,512	$2,565,154	$2,558,795	$2,552,437	$2,546,078	$2,539,720	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$16,998	$16,956	$16,915	$16,873	$16,832	$16,790	$16,833	$16,792	$16,750	$16,708	$16,667	$16,625	$201,739
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$3,041	$3,034	$3,026	$3,019	$3,011	$3,004	$2,874	$2,867	$2,860	$2,853	$2,846	$2,839	$35,275
8. Investment Expenses														
a. Depreciation [d]		$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$76,302
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$26,397	$26,348	$26,299	$26,251	$26,202	$26,153	$26,066	$26,017	$25,969	$25,920	$25,871	$25,822	$313,316

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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23 - SPCC - Spill Prevention, Control & Countermeasures	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	Total
1. Investments														
a. Expenditures/Additions	$0	($10,937)	($283)	$24,217	$21,865	$3,863	$8,284	$56,394	$12,423	$7,464	($9,112)	($90,467)	$495,253	$518,963
b. Clearings to Plant	$0	$31,839	($1,695)	$140,969	($137,186)	($5,129)	$37,285	$84,938	($60,871)	$0	$8,744	$96,265	$6,323	$201,482
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($8,126)	$0	$0	($8,126)
d. Other	$0	($418)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($418)
2. Plant-In Service/Depreciation Base [a]	$16,329,193	$16,361,032	$16,359,337	$16,500,306	$16,363,119	$16,357,991	$16,395,276	$16,480,214	$16,419,343	$16,419,343	$16,428,087	$16,524,352	$16,530,675	
3a. Less: Accumulated Depreciation	$3,325,715	$3,366,273	$3,407,289	$3,448,401	$3,489,518	$3,530,531	$3,571,589	$3,612,758	$3,653,944	$3,695,086	$3,728,110	$3,769,338	$3,810,646	
3b. Less: Capital Recovery Unamortized Balance	($2,837,506)	($2,813,860)	($2,790,214)	($2,766,568)	($2,742,922)	($2,719,276)	($2,695,630)	($2,671,984)	($2,648,339)	($2,624,693)	($2,601,047)	($2,577,401)	($2,553,755)	
4. CWIP - Non Interest Bearing	$23,310	$12,373	$12,090	$36,307	$58,172	$62,035	$70,319	$126,713	$139,136	$146,600	$137,488	$47,020	$542,273	
5. Net Investment (Lines 2 - 3 + 4)	$15,864,294	$15,820,992	$15,754,352	$15,854,780	$15,674,695	$15,608,771	$15,589,636	$15,666,153	$15,552,873	$15,495,550	$15,438,511	$15,379,436	$15,816,057	
6. Average Net Investment		$15,842,643	$15,787,672	$15,804,566	$15,764,738	$15,641,733	$15,599,203	$15,627,894	$15,609,513	$15,524,211	$15,467,030	$15,408,973	$15,597,746	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$103,188	$102,830	$102,940	$102,681	$101,879	$101,602	$102,301	$102,180	$101,622	$101,248	$100,868	$102,103	$1,225,442
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$18,461	$18,397	$18,417	$18,371	$18,227	$18,178	$17,469	$17,448	$17,353	$17,289	$17,224	$17,435	$214,270
8. Investment Expenses														
a. Depreciation [d]		$40,976	$41,016	$41,112	$41,117	$41,013	$41,058	$41,169	$41,186	$41,142	$41,150	$41,228	$41,308	$493,475
b. Amortization [e]		$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$283,751
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$186,272	$185,889	$186,115	$185,814	$184,766	$184,484	$184,584	$184,461	$183,763	$183,332	$182,965	$184,493	$2,216,938

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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24 - Manatee Reburn	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	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	($122)	($122)
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17	$17
2. Plant-In Service/Depreciation Base [a]	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,736	
3a. Less: Accumulated Depreciation	$8,384,671	$8,511,243	$8,637,815	$8,764,388	$8,890,960	$9,017,532	$9,144,104	$9,270,677	$9,397,249	$9,523,821	$9,650,394	$9,776,966	$9,903,555	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	
5. Net Investment (Lines 2 - 3 + 4)	$23,272,426	$23,145,854	$23,019,282	$22,892,709	$22,766,137	$22,639,565	$22,512,992	$22,386,420	$22,259,848	$22,133,275	$22,006,703	$21,880,131	$21,753,420	
6. Average Net Investment		$23,209,140	$23,082,568	$22,955,995	$22,829,423	$22,702,851	$22,576,279	$22,449,706	$22,323,134	$22,196,562	$22,069,989	$21,943,417	$21,816,775	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$151,168	$150,344	$149,519	$148,695	$147,871	$147,046	$146,956	$146,128	$145,299	$144,471	$143,642	$142,813	$1,763,954
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$27,046	$26,898	$26,751	$26,603	$26,456	$26,308	$25,094	$24,953	$24,811	$24,670	$24,528	$24,387	$308,505
8. Investment Expenses														
a. Depreciation [d]		$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$1,518,867
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$304,786	$303,814	$302,842	$301,871	$300,899	$299,927	$298,623	$297,653	$296,683	$295,713	$294,743	$293,772	$3,591,326

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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25 - Pt. Everglades ESP Technology	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$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	
3a. Less: Accumulated Depreciation	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	
3b. Less: Capital Recovery Unamortized Balance	$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)	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	
6. Average Net Investment		$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Investment Expenses														
a. Depreciation [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$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 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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26 - UST Remove/Replacement	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	
3a. Less: Accumulated Depreciation	$47,708	$47,852	$47,996	$48,141	$48,285	$48,429	$48,574	$48,718	$48,862	$49,007	$49,151	$49,295	$49,440	
3b. Less: Capital Recovery Unamortized Balance	$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)	$67,739	$67,595	$67,450	$67,306	$67,162	$67,017	$66,873	$66,729	$66,584	$66,440	$66,296	$66,151	$66,007	
6. Average Net Investment		$67,667	$67,522	$67,378	$67,234	$67,089	$66,945	$66,801	$66,657	$66,512	$66,368	$66,224	$66,079	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$441	$440	$439	$438	$437	$436	$437	$436	$435	$434	$434	$433	$5,240
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$79	$79	$79	$78	$78	$78	$75	$75	$74	$74	$74	$74	$916
8. Investment Expenses														
a. Depreciation [d]		$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,732
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$664	$663	$662	$661	$659	$658	$656	$655	$654	$653	$652	$651	$7,888

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

FLORIDA POWER & LIGHT COMPANY
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28 - CWA 316(b) Phase II Rule	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	Total
1. Investments														
a. Expenditures/Additions	$0	$10,876	$5,482	$2,172	$6,895	$56,979	$11,817	$10,833	$114,691	$61,674	($624,986)	$0	$0	($343,567)
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$687,829	$66,242	$12,574	$766,645
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$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	$687,829	$754,071	$766,645	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$771	$2,387	$4,092	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$343,567	$354,443	$359,925	$362,097	$368,992	$425,971	$437,788	$448,621	$563,312	$624,986	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$343,567	$354,443	$359,925	$362,097	$368,992	$425,971	$437,788	$448,621	$563,312	$624,986	$687,058	$751,684	$762,553	
6. Average Net Investment		$349,005	$357,184	$361,011	$365,544	$397,481	$431,880	$443,205	$505,967	$594,149	$656,022	$719,371	$757,118	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,273	$2,326	$2,351	$2,381	$2,589	$2,813	$2,901	$3,312	$3,889	$4,294	$4,709	$4,956	$38,796
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$407	$416	$421	$426	$463	$503	$495	$566	$664	$733	$804	$846	$6,745
8. Investment Expenses														
a. Depreciation [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$771	$1,616	$1,704	$4,092
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,680	$2,743	$2,772	$2,807	$3,052	$3,316	$3,397	$3,878	$4,553	$5,799	$7,129	$7,507	$49,632

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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31 - Clean Air Interstate Rule (CAIR) Compliance	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	Total
1. Investments														
a. Expenditures/Additions	$0	$41,015	$992	($41,537)	$2,110	$737	$43,258	$171	$7,653	$9,026	$3,645	$1,202	($68,703)	($430)
b. Clearings to Plant	$0	$3,833	$0	$1,756	$11	($24,030)	$0	$0	($2,494,657)	$0	$0	$0	$79,730	($2,433,357)
c. Retirements	$0	$0	$0	($41,546)	$0	($24,395)	$0	$0	($2,084,194)	$0	$0	$0	$0	($2,150,135)
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	($107,815)	$0	$0	$0	$0	($107,815)
2. Plant-In Service/Depreciation Base [a]	$527,147,489	$527,151,322	$527,151,322	$527,153,078	$527,153,089	$527,129,059	$527,129,059	$527,129,059	$524,634,402	$524,634,402	$524,634,402	$524,634,402	$524,714,132	
3a. Less: Accumulated Depreciation	$69,676,106	$70,994,656	$72,313,209	$73,590,218	$74,908,775	$76,202,889	$77,521,352	$78,839,815	$77,963,421	$79,277,069	$80,590,716	$81,904,364	$83,218,088	
3b. Less: Capital Recovery Unamortized Balance	($77,096)	($76,454)	($75,811)	($75,169)	($74,526)	($73,884)	($73,241)	($72,599)	($71,956)	($71,314)	($70,671)	($70,029)	($69,386)	
4. CWIP - Non Interest Bearing	$430	$41,446	$42,438	$901	$3,011	$3,748	$47,007	$47,177	$54,830	$63,857	$67,502	$68,703	$0	
5. Net Investment (Lines 2 - 3 + 4)	$457,548,909	$456,274,566	$454,956,362	$453,638,929	$452,321,851	$451,003,802	$449,727,954	$448,409,020	$446,797,767	$445,492,504	$444,181,859	$442,868,770	$441,565,430	
6. Average Net Investment		$456,911,738	$455,615,464	$454,297,646	$452,980,390	$451,662,826	$450,365,878	$449,068,487	$447,603,394	$446,145,136	$444,837,181	$443,525,315	$442,217,100	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,976,007	$2,967,564	$2,958,981	$2,950,401	$2,941,820	$2,933,372	$2,939,617	$2,930,026	$2,920,480	$2,911,918	$2,903,331	$2,894,767	$35,228,284
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$532,439	$530,929	$529,393	$527,858	$526,323	$524,811	$501,969	$500,331	$498,701	$497,239	$495,773	$494,310	$6,160,076
8. Investment Expenses														
a. Depreciation [d]		$1,318,550	$1,318,553	$1,318,555	$1,318,557	$1,318,510	$1,318,463	$1,318,463	$1,315,616	$1,313,648	$1,313,648	$1,313,648	$1,313,725	$15,799,933
b. Amortization [e]		$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$7,710
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$4,827,639	$4,817,689	$4,807,571	$4,797,458	$4,787,294	$4,777,289	$4,760,691	$4,746,615	$4,733,471	$4,723,447	$4,713,393	$4,703,445	$57,196,003

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

  Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
  - Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
  - Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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33 - MATS Project	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$250	($246)	$0	($4)	$21	$0	$0	($27)	$0	$6	$0
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($6)
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,932	
3a. Less: Accumulated Depreciation	$18,609,993	$18,860,358	$19,110,724	$19,361,089	$19,611,455	$19,861,821	$20,112,186	$20,362,552	$20,612,918	$20,863,283	$21,113,649	$21,364,014	$21,614,380	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$0	$0	$0	$250	$4	$4	$0	$21	$21	$21	($6)	($6)	$0	
5. Net Investment (Lines 2 - 3 + 4)	$88,885,946	$88,635,580	$88,385,214	$88,135,099	$87,884,487	$87,634,122	$87,383,752	$87,133,407	$86,883,042	$86,632,676	$86,382,283	$86,131,918	$85,881,552	
6. Average Net Investment		$88,760,763	$88,510,397	$88,260,157	$88,009,793	$87,759,305	$87,508,937	$87,258,580	$87,008,224	$86,757,859	$86,507,480	$86,257,101	$86,006,735	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$578,126	$576,496	$574,866	$573,235	$571,603	$569,973	$571,197	$569,559	$567,920	$566,281	$564,642	$563,003	$6,846,900
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$103,433	$103,141	$102,850	$102,558	$102,266	$101,974	$97,538	$97,258	$96,978	$96,698	$96,418	$96,138	$1,197,249
8. Investment Expenses														
a. Depreciation [d]		$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$3,004,388
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$931,925	$930,002	$928,081	$926,158	$924,235	$922,313	$919,101	$917,182	$915,263	$913,344	$911,426	$909,507	$11,048,537

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

- Average Net Investment: See footnotes (b) and (c).
- Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

- Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.
- Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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34 - St Lucie Cooling Water System Inspection & Maintenance	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	Total
1. Investments														
a. Expenditures/Additions	$0	$4,343	$3,590	$4,035	$8,404	$2,695	$10,582	$10,139	$12,877	$10,210	$8,119	$1,942	$3,850	$80,786
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	$0	$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	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$4,417,723	$4,422,066	$4,425,656	$4,429,691	$4,438,095	$4,440,790	$4,451,372	$4,461,511	$4,474,388	$4,484,598	$4,492,717	$4,494,659	$4,498,509	
5. Net Investment (Lines 2 - 3 + 4)	$4,417,723	$4,422,066	$4,425,656	$4,429,691	$4,438,095	$4,440,790	$4,451,372	$4,461,511	$4,474,388	$4,484,598	$4,492,717	$4,494,659	$4,498,509	
6. Average Net Investment		$4,419,894	$4,423,861	$4,427,674	$4,433,893	$4,439,443	$4,446,081	$4,456,442	$4,467,950	$4,479,493	$4,488,658	$4,493,688	$4,496,584	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$28,788	$28,814	$28,839	$28,879	$28,915	$28,959	$29,172	$29,247	$29,323	$29,383	$29,416	$29,435	$349,170
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$5,151	$5,155	$5,160	$5,167	$5,173	$5,181	$4,981	$4,994	$5,007	$5,017	$5,023	$5,026	$61,036
8. Investment Expenses														
a. Depreciation [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$33,939	$33,969	$33,998	$34,046	$34,089	$34,140	$34,153	$34,242	$34,330	$34,400	$34,439	$34,461	$410,206

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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35 - Martin Plant Drinking Water System Compliance	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	
3a. Less: Accumulated Depreciation	$38,370	$38,864	$39,359	$39,853	$40,347	$40,842	$41,336	$41,830	$42,325	$42,819	$43,313	$43,808	$44,302	
3b. Less: Capital Recovery Unamortized Balance	$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)	$197,021	$196,527	$196,033	$195,538	$195,044	$194,550	$194,055	$193,561	$193,067	$192,572	$192,078	$191,584	$191,090	
6. Average Net Investment		$196,774	$196,280	$195,786	$195,291	$194,797	$194,303	$193,808	$193,314	$192,820	$192,325	$191,831	$191,337	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,282	$1,278	$1,275	$1,272	$1,269	$1,266	$1,269	$1,265	$1,262	$1,259	$1,256	$1,252	$15,205
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$229	$229	$228	$228	$227	$226	$217	$216	$216	$215	$214	$214	$2,659
8. Investment Expenses														
a. Depreciation [d]		$494	$494	$494	$494	$494	$494	$494	$494	$494	$494	$494	$494	$5,932
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,005	$2,001	$1,998	$1,994	$1,990	$1,986	$1,980	$1,976	$1,972	$1,968	$1,964	$1,961	$23,796

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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36 - Low-Level Radioactive Waste Storage	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	
3a. Less: Accumulated Depreciation	$1,064,031	$1,103,990	$1,143,948	$1,183,907	$1,223,866	$1,263,825	$1,303,784	$1,343,742	$1,383,701	$1,423,660	$1,463,619	$1,503,578	$1,543,536	
3b. Less: Capital Recovery Unamortized Balance	$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)	$16,392,773	$16,352,814	$16,312,855	$16,272,896	$16,232,938	$16,192,979	$16,153,020	$16,113,061	$16,073,102	$16,033,144	$15,993,185	$15,953,226	$15,913,267	
6. Average Net Investment		$16,372,793	$16,332,835	$16,292,876	$16,252,917	$16,212,958	$16,172,999	$16,133,041	$16,093,082	$16,053,123	$16,013,164	$15,973,205	$15,933,247	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$106,641	$106,381	$106,121	$105,860	$105,600	$105,340	$105,607	$105,346	$105,084	$104,823	$104,561	$104,300	$1,265,663
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$19,079	$19,033	$18,986	$18,940	$18,893	$18,846	$18,034	$17,989	$17,944	$17,900	$17,855	$17,810	$221,308
8. Investment Expenses														
a. Depreciation [d]		$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$479,506
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$165,679	$165,372	$165,065	$164,759	$164,452	$164,145	$163,600	$163,293	$162,987	$162,681	$162,375	$162,069	$1,966,477

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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37 - DeSoto Next Generation Solar Energy Center	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
b. Clearings to Plant	$0	($47,662)	$0	($46,992)	($21,121)	$0	$0	$0	($1,052)	$0	($4,256)	$0	$86,055	($35,027)
c. Retirements	$0	($49,116)	$0	$0	($21,238)	$0	$0	$0	$0	$0	$0	$0	($9,201)	($79,555)
d. Other	$0	($0)	($1,677)	($5,600)	$0	$0	$0	$0	$0	$0	$0	$0	($813)	($8,091)
2. Plant-In Service/Depreciation Base [a]	$153,566,725	$153,519,064	$153,519,064	$153,472,071	$153,450,951	$153,450,951	$153,450,951	$153,450,951	$153,449,899	$153,449,899	$153,445,642	$153,445,642	$153,531,698	
3a. Less: Accumulated Depreciation	$36,158,682	$36,554,171	$36,996,847	$37,435,608	$37,858,675	$38,302,854	$38,747,034	$39,191,214	$39,635,392	$40,079,569	$40,523,740	$40,967,905	$41,402,609	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
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)	$117,408,043	$116,964,892	$116,522,217	$116,036,464	$115,592,277	$115,148,097	$114,703,917	$114,259,737	$113,814,507	$113,370,330	$112,921,903	$112,477,738	$112,129,090	
6. Average Net Investment		$117,186,468	$116,743,555	$116,279,340	$115,814,370	$115,370,187	$114,926,007	$114,481,827	$114,037,122	$113,592,419	$113,146,117	$112,699,821	$112,303,414	
a. Average ITC Balance		$33,385,161	$33,263,095	$33,141,029	$33,018,963	$32,896,897	$32,774,831	$32,652,765	$32,530,699	$32,408,633	$32,286,567	$32,164,501	$32,042,435	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$837,053	$833,899	$830,605	$827,307	$824,144	$820,981	$826,126	$822,928	$819,730	$816,522	$813,313	$810,432	$9,883,040
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$147,621	$147,065	$146,483	$145,901	$145,343	$144,785	$138,162	$137,627	$137,092	$136,555	$136,018	$135,536	$1,698,187
8. Investment Expenses														
a. Depreciation [d]		$432,418	$432,167	$432,174	$432,118	$431,993	$431,993	$431,993	$431,991	$431,990	$431,984	$431,978	$432,531	$5,185,329
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($1,924,740)
9. Total System Recoverable Costs (Lines 7 & 8)		$1,268,885	$1,264,922	$1,261,055	$1,257,118	$1,253,272	$1,249,551	$1,248,072	$1,244,338	$1,240,603	$1,236,852	$1,233,101	$1,230,291	$14,988,059

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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38 - Space Coast Next Generation Solar Energy Center	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	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	($301)	$0	($10,800)	$0	($37,455)	$0	$0	$0	$0	$0	$0	$0	($48,556)
c. Retirements	$0	$0	$0	($6,741)	$0	($37,455)	$0	$0	$0	$0	$0	$0	$0	($44,196)
d. Other	$0	$0	$0	($4,059)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4,059)
2. Plant-In Service/Depreciation Base [a]	$70,650,306	$70,650,005	$70,650,005	$70,639,205	$70,639,205	$70,601,750	$70,601,750	$70,601,750	$70,601,750	$70,601,750	$70,601,750	$70,601,750	$70,601,750	
3a. Less: Accumulated Depreciation	$15,914,281	$16,114,861	$16,315,439	$16,505,172	$16,705,658	$16,868,467	$17,068,508	$17,268,549	$17,468,590	$17,668,631	$17,868,672	$18,068,713	$18,268,753	
3b. Less: Capital Recovery Unamortized Balance	$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)	$54,736,024	$54,535,145	$54,334,566	$54,134,033	$53,933,546	$53,733,283	$53,533,242	$53,333,201	$53,133,160	$52,933,119	$52,733,078	$52,533,037	$52,332,997	
6. Average Net Investment		$54,635,585	$54,434,855	$54,234,300	$54,033,790	$53,833,415	$53,633,262	$53,433,221	$53,233,180	$53,033,140	$52,833,099	$52,633,058	$52,433,017	
a. Average ITC Balance		$14,281,599	$14,230,410	$14,179,221	$14,128,032	$14,076,843	$14,025,654	$13,974,465	$13,923,276	$13,872,087	$13,820,898	$13,769,709	$13,718,520	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$387,421	$386,000	$384,581	$383,162	$381,744	$380,327	$382,611	$381,182	$379,752	$378,322	$376,892	$375,463	$4,577,456
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$68,400	$68,149	$67,898	$67,648	$67,397	$67,147	$64,090	$63,851	$63,611	$63,372	$63,132	$62,893	$787,588
8. Investment Expenses														
a. Depreciation [d]		$196,187	$196,187	$196,141	$196,095	$195,872	$195,649	$195,649	$195,649	$195,649	$195,649	$195,649	$195,649	$2,350,023
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($807,156)
9. Total System Recoverable Costs (Lines 7 & 8)		$589,137	$587,465	$585,749	$584,033	$582,142	$580,252	$579,480	$577,810	$576,141	$574,472	$572,802	$571,133	$6,960,615

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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39 - Martin Next Generation Solar Energy Center	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	Total
1. Investments														
a. Expenditures/Additions	$0	$265,626	$709,327	$9,378	$173,636	($330,037)	($1,052,026)	($205,953)	$144,922	$53,006	$118,162	$438,170	$208,937	$533,149
b. Clearings to Plant	$0	$258,639	($34,426)	$52,033	($52,373)	$694,336	$614,510	$20,367	($30,148)	$46	$2,623	($464)	$15,749	$1,540,894
c. Retirements	$0	($361,777)	$0	($106,929)	($47,794)	$0	($536,251)	$0	$0	$0	$0	$0	($45,086)	($1,097,837)
d. Other	$0	($66,874)	($93,382)	$27,469	($22,473)	($23,941)	($2,117)	$33,037	($5,823)	$0	($6,731)	($30,692)	($8,409)	($199,937)
2. Plant-In Service/Depreciation Base [a]	$422,853,922	$423,112,561	$423,078,135	$423,130,169	$423,077,796	$423,772,131	$424,386,641	$424,407,008	$424,376,860	$424,376,907	$424,379,530	$424,379,066	$424,394,815	
3a. Less: Accumulated Depreciation	$79,701,478	$80,341,013	$81,316,330	$82,305,635	$83,304,133	$84,349,730	$84,882,473	$85,987,384	$87,053,430	$88,125,271	$89,190,383	$90,231,546	$91,249,931	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$1,321,775	$1,587,401	$2,296,728	$2,306,106	$2,479,742	$2,149,705	$1,097,679	$891,726	$1,036,648	$1,089,655	$1,207,816	$1,645,986	$1,854,924	
5. Net Investment (Lines 2 - 3 + 4)	$344,474,219	$344,358,949	$344,058,533	$343,130,640	$342,253,406	$341,572,107	$340,601,847	$339,311,350	$338,360,079	$337,341,291	$336,396,963	$335,793,507	$334,999,808	
6. Average Net Investment		$344,416,584	$344,208,741	$343,594,586	$342,692,023	$341,912,756	$341,086,977	$339,956,599	$338,835,715	$337,850,685	$336,869,127	$336,095,235	$335,396,658	
a. Average ITC Balance		$98,597,929	$98,254,131	$97,910,333	$97,566,535	$97,222,737	$96,878,939	$96,535,141	$96,191,343	$95,847,545	$95,503,747	$95,159,949	$94,816,151	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,461,194	$2,459,081	$2,454,321	$2,447,682	$2,441,847	$2,435,708	$2,452,195	$2,444,050	$2,436,794	$2,429,561	$2,423,687	$2,418,306	$29,304,425
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$434,024	$433,668	$432,838	$431,673	$430,651	$429,574	$410,142	$408,781	$407,573	$406,369	$405,396	$404,508	$5,035,197
8. Investment Expenses														
a. Depreciation [d]		$1,018,631	$1,019,145	$1,019,210	$1,019,210	$1,019,983	$1,021,556	$1,022,318	$1,022,314	$1,022,286	$1,022,289	$1,022,299	$1,022,325	$12,251,567
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($5,421,012)
9. Total System Recoverable Costs (Lines 7 & 8)		$3,511,653	$3,509,697	$3,504,173	$3,496,369	$3,490,284	$3,484,643	$3,482,459	$3,472,949	$3,464,457	$3,456,022	$3,449,186	$3,442,943	$41,764,837

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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41 - Manatee Temporary Heating System	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$0	$0	$18,514	$36,127	$0	$461,790	$46,451	$597,809	$1,160,691
b. Clearings to Plant	$0	$0	($52,273)	$0	$0	$0	$0	$0	$0	$0	($1,119)	$0	($16,244)	($69,637)
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,119)	$0	($16,244)	($17,364)
d. Other	$0	$0	($52,273)	$0	$0	$0	$20,138	$0	$0	$0	$0	$0	$0	($32,135)
2. Plant-In Service/Depreciation Base [a]	$5,805,515	$5,805,515	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,752,122	$5,752,122	$5,735,878	
3a. Less: Accumulated Depreciation	$5,554,368	$5,554,562	$5,502,891	$5,503,085	$5,503,278	$5,503,471	$5,523,803	$5,523,996	$5,524,190	$5,524,383	$5,523,457	$5,523,651	$5,507,503	
3b. Less: Capital Recovery Unamortized Balance	$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	$18,514	$54,642	$54,642	$516,431	$562,882	$1,160,691	
5. Net Investment (Lines 2 - 3 + 4)	$251,146	$250,953	$250,350	$250,157	$249,963	$249,770	$229,438	$247,759	$283,693	$283,500	$745,096	$791,354	$1,389,066	
6. Average Net Investment		$251,050	$250,652	$250,253	$250,060	$249,867	$239,604	$238,599	$265,726	$283,597	$514,298	$768,225	$1,090,210	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,635	$1,633	$1,630	$1,629	$1,627	$1,561	$1,562	$1,739	$1,856	$3,367	$5,029	$7,137	$30,404
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$293	$292	$292	$291	$291	$279	$267	$297	$317	$575	$859	$1,219	$5,271
8. Investment Expenses														
a. Depreciation [d]		$193	$603	$193	$193	$193	$193	$193	$193	$193	$193	$193	$97	$2,633
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,121	$2,527	$2,115	$2,113	$2,112	$2,033	$2,022	$2,230	$2,367	$4,135	$6,081	$8,452	$38,309

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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42 - Turkey Point Cooling Canal Monitoring Plan	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	Total
1. Investments														
a. Expenditures/Additions	$0	$198,623	$186,781	$942,232	$463,409	$276,597	$408,217	$793,223	$1,301,797	$1,479,660	$3,196,744	$1,847,488	$1,327,435	$12,422,206
b. Clearings to Plant	$0	($130,651)	$0	($25,796)	$2,749	$49,710	$0	$0	$0	$0	$0	$0	$0	($103,988)
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$17,170,089	$17,039,438	$17,039,438	$17,013,641	$17,016,390	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$17,066,101	
3a. Less: Accumulated Depreciation	$549,921	$594,536	$638,980	$683,391	$727,772	$772,221	$816,735	$861,249	$905,763	$950,278	$994,792	$1,039,306	$1,083,820	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$6,953,906	$7,152,528	$7,339,310	$8,281,542	$8,744,951	$9,021,548	$9,429,765	$10,222,988	$11,524,785	$13,004,445	$16,201,188	$18,048,676	$19,376,111	
5. Net Investment (Lines 2 - 3 + 4)	$23,574,074	$23,597,431	$23,739,767	$24,611,792	$25,033,570	$25,315,427	$25,679,130	$26,427,839	$27,685,122	$29,120,268	$32,272,497	$34,075,471	$35,358,392	
6. Average Net Investment		$23,585,752	$23,668,599	$24,175,780	$24,822,681	$25,174,498	$25,497,279	$26,053,485	$27,056,481	$28,402,695	$30,696,382	$33,173,984	$34,716,931	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$153,621	$154,161	$157,464	$161,678	$163,969	$166,072	$170,547	$177,113	$185,925	$200,939	$217,158	$227,258	$2,135,905
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$27,484	$27,581	$28,172	$28,926	$29,336	$29,712	$29,123	$30,244	$31,749	$34,312	$37,082	$38,807	$372,527
8. Investment Expenses														
a. Depreciation [d]		$44,615	$44,445	$44,411	$44,381	$44,449	$44,514	$44,514	$44,514	$44,514	$44,514	$44,514	$44,514	$533,899
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$225,721	$226,186	$230,047	$234,984	$237,754	$240,298	$244,184	$251,870	$262,188	$279,766	$298,754	$310,579	$3,042,331

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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44 - Martin Plant Barley Barber Swamp Iron Mitigation	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	
3a. Less: Accumulated Depreciation	$19,114	$19,460	$19,806	$20,152	$20,498	$20,844	$21,190	$21,536	$21,882	$22,228	$22,574	$22,919	$23,265	
3b. Less: Capital Recovery Unamortized Balance	$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)	$145,604	$145,258	$144,912	$144,566	$144,220	$143,875	$143,529	$143,183	$142,837	$142,491	$142,145	$141,799	$141,453	
6. Average Net Investment		$145,431	$145,085	$144,739	$144,393	$144,048	$143,702	$143,356	$143,010	$142,664	$142,318	$141,972	$141,626	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$947	$945	$943	$940	$938	$936	$938	$936	$934	$932	$929	$927	$11,246
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$169	$169	$169	$168	$168	$167	$160	$160	$159	$159	$159	$158	$1,966
8. Investment Expenses														
a. Depreciation [d]		$346	$346	$346	$346	$346	$346	$346	$346	$346	$346	$346	$346	$4,151
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$1,463	$1,460	$1,457	$1,455	$1,452	$1,449	$1,445	$1,442	$1,439	$1,437	$1,434	$1,431	$17,363

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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

FORM: 42-8A

JANUARY 2017 THROUGH DECEMBER 2017

45 - 800 MW Unit ESP	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	Total
1. Investments														
a. Expenditures/Additions	$0	$16,877	$9,625	($2,838)	$0	($23,664)	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant	$0	$7,781	$3,385	$76	$31,649	($44,692)	$0	$0	$0	$0	$0	$0	$0	($1,801)
c. Retirements	$0	$0	$0	$0	$0	($77,442)	$0	$0	$0	$0	$0	$0	$0	($77,442)
d. Other	$0	($824)	($745)	$218	($766)	($211)	$0	$0	$0	$0	$0	$0	$0	($2,328)
2. Plant-In Service/Depreciation Base [a]	$214,906,214	$214,913,995	$214,917,380	$214,917,457	$214,949,105	$214,904,413	$214,904,413	$214,904,413	$214,904,413	$214,904,413	$214,904,413	$214,904,413	$214,904,413	
3a. Less: Accumulated Depreciation	$17,315,970	$18,143,730	$18,971,588	$19,800,416	$20,628,315	$21,379,299	$22,207,851	$23,036,403	$23,864,955	$24,693,507	$25,522,059	$26,350,611	$27,179,395	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$0	$16,877	$26,502	$23,664	$23,664	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$197,590,244	$196,787,143	$195,972,294	$195,140,705	$194,344,455	$193,525,114	$192,696,562	$191,868,010	$191,039,458	$190,210,906	$189,382,354	$188,553,802	$187,725,018	
6. Average Net Investment		$197,188,693	$196,379,718	$195,556,500	$194,742,580	$193,934,784	$193,110,838	$192,282,286	$191,453,734	$190,625,182	$189,796,630	$188,968,078	$188,139,410	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,284,351	$1,279,082	$1,273,720	$1,268,419	$1,263,157	$1,257,791	$1,258,686	$1,253,262	$1,247,838	$1,242,415	$1,236,991	$1,231,567	$15,097,278
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$229,784	$228,841	$227,882	$226,934	$225,992	$225,032	$214,933	$214,007	$213,081	$212,155	$211,229	$210,302	$2,640,171
8. Investment Expenses														
a. Depreciation [d]		$828,584	$828,603	$828,609	$828,666	$828,637	$828,552	$828,552	$828,552	$828,552	$828,552	$828,552	$828,784	$9,943,195
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,342,719	$2,336,526	$2,330,211	$2,324,018	$2,317,787	$2,311,375	$2,302,171	$2,295,821	$2,289,471	$2,283,121	$2,276,772	$2,270,653	$27,680,644

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

□ Average Net Investment: See footnotes (b) and (c).

□ Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

□ Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

□ Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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

FORM: 42-8A

JANUARY 2017 THROUGH DECEMBER 2017

54 - Coal Combustion Residuals	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	Total
1. Investments														
a. Expenditures/Additions	$0	$763,706	$204,630	$373,530	$586,516	$554,383	$667,969	$521,536	$851,471	$876,983	$1,636,520	$1,834,341	$12,289,551	$21,161,136
b. Clearings to Plant	$0	($1,216)	$166	($166)	$1,114	$345	$334	$0	$0	$0	$0	$0	$5,391	$5,968
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$254,590	$253,373	$253,539	$253,373	$254,488	$254,832	$255,167	$255,167	$255,167	$255,167	$255,167	$255,167	$260,558	
3a. Less: Accumulated Depreciation	$486	$787	$1,086	$1,386	$1,687	$1,988	$2,289	$2,590	$2,892	$3,193	$3,495	$3,796	$4,101	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$3,026,212	$3,789,917	$3,994,548	$4,368,078	$4,954,595	$5,508,977	$6,176,946	$6,698,482	$7,549,953	$8,426,936	$10,063,456	$11,897,797	$24,187,348	
5. Net Investment (Lines 2 - 3 + 4)	$3,280,315	$4,042,504	$4,247,001	$4,620,065	$5,207,396	$5,761,822	$6,429,824	$6,951,058	$7,802,228	$8,678,909	$10,315,128	$12,149,168	$24,443,805	
6. Average Net Investment		$3,661,410	$4,144,753	$4,433,533	$4,913,730	$5,484,609	$6,095,823	$6,690,441	$7,376,643	$8,240,568	$9,497,018	$11,232,148	$18,296,487	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$23,848	$26,996	$28,877	$32,005	$35,723	$39,704	$43,796	$48,288	$53,943	$62,168	$73,526	$119,769	$588,642
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$4,267	$4,830	$5,166	$5,726	$6,391	$7,103	$7,479	$8,246	$9,211	$10,616	$12,555	$20,452	$102,042
8. Investment Expenses														
a. Depreciation [d]		$301	$300	$300	$300	$301	$301	$301	$301	$301	$301	$301	$305	$3,615
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$28,415	$32,126	$34,343	$38,031	$42,415	$47,109	$51,576	$56,835	$63,456	$73,085	$86,383	$140,526	$694,299

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

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Docket No. 20180007-EI
2017 ECRC Final True Up Calculation
Exhibit RBD-1, Page 41 of 47

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

JANUARY 2017 THROUGH DECEMBER 2017

	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	$0
b. 158.200 Allowances Withheld	$0	$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	$0
d. 254.900 Other Regulatory Liabilities-Gains	($5,046)	($4,699)	($4,353)	($4,006)	($3,792)	($3,432)	($3,071)	($2,728)	($2,354)	($1,986)	($1,619)	($1,252)	($885)	($34,177)
2. Total Working Capital	($5,046)	($4,699)	($4,353)	($4,006)	($3,792)	($3,432)	($3,071)	($2,728)	($2,354)	($1,986)	($1,619)	($1,252)	($885)	($34,177)
3. Average Net Working Capital Balance		($4,873)	($4,526)	($4,179)	($3,899)	($3,612)	($3,251)	($2,899)	($2,541)	($2,170)	($1,803)	($1,436)	($1,069)	($36,258)
4. Return on Average Net Working Capital Balance														
a. Equity Component grossed up for taxes [a]		($32)	($29)	($27)	($25)	($24)	($21)	($19)	($17)	($14)	($12)	($9)	($7)	($237)
b. Debt Component [b]		($6)	($5)	($5)	($5)	($4)	($4)	($3)	($3)	($2)	($2)	($2)	($1)	($42)
5. Total Return Component [c]		($37)	($35)	($32)	($30)	($28)	($25)	($22)	($19)	($17)	($14)	($11)	($8)	($278)
6. Expense Dr (Cr)														
a. 411.800 Gains from Dispositions of Allowances		($347)	($347)	($347)	($347)	($361)	($361)	($361)	($374)	($367)	($367)	($367)	($119,547)	($123,492)
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) [d]		($347)	($347)	($347)	($347)	($361)	($361)	($361)	($374)	($367)	($367)	($367)	($119,547)	($123,492)
8. Total System Recoverable Expenses (Lines 5+7)		($384)	($381)	($379)	($377)	($389)	($386)	($383)	($394)	($384)	($381)	($378)	($119,555)	($123,771)
a. Recoverable Costs Allocated to Energy		($384)	($381)	($379)	($377)	($389)	($386)	($383)	($394)	($384)	($381)	($378)	($119,555)	($123,771)
b. Recoverable Costs Allocated to Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Energy Jurisdictional Factor		94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	
10. Demand Jurisdictional Factor		95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	
11. Retail Energy-Related Recoverable Costs [e]		($365)	($362)	($359)	($357)	($369)	($366)	($364)	($374)	($364)	($361)	($359)	($113,448)	($117,448)
12. Retail Demand-Related Recoverable Costs [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total Jurisdictional Recoverable Costs (Lines11+12)		($365)	($362)	($359)	($357)	($369)	($366)	($364)	($374)	($364)	($361)	($359)	($113,448)	($117,448)

[a] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Reportt and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[b] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[c] Line 8a times Line 9

[d] Line 8b times Line 10

[e] Line 5 is Reportted on Capital Schedule

[f] Line 7 is Reportted on O&M Schedule

Florida Power & Light Company
Environmental Cost Recovery Clause
2017 Annual Capital Depreciation Schedule

Project	Function	Unit	Utility	Depreciation Rate / Amortization Period	Plant Balance December 2016	Plant Balance December 2017
002-LOW NOX BURNER TECHNOLOGY	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%	-	-
002-LOW NOX BURNER TECHNOLOGY Total					-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	65,605	65,605
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31100	1.74%	56,430	56,430
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31200	4.64%	558,926	424,505
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31100	1.83%	56,333	56,333
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31200	4.99%	599,476	468,728
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31200	4.45%	31,632	31,632
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31650	5-Year	58,207	58,207
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31670	7-Year	66,897	66,897
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31100	2.68%	36,811	36,811
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31200	4.53%	533,645	338,939
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31100	2.39%	36,845	36,845
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31200	4.64%	529,520	335,746
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Scherer U4	31200	2.79%	515,653	515,653
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	43,193	43,193
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP U1	31200	2.12%	780	780
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP U2	31200	2.35%	780	780
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31200	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	58,860	58,860
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34500	1.60%	34,502	34,502
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	10,225	10,225
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U4	34300	4.11%	487,395	441,310
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U5	34300	5.00%	498,340	556,314
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U2	34300	3.46%	165,032	368,561
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3 SC Peaker	34300	4.54%	2,283	141,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Manatee U3	34300	3.35%	87,691	87,691
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U3	34300	4.49%	421,385	499,129
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U4	34300	3.92%	413,986	491,342
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U8	34300	3.37%	13,693	13,693
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U4	34300	4.00%	171,843	310,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U5	34300	4.12%	134,809	273,035
003-CONTINUOUS EMISSION MONITORING Total					**5,690,778**	**5,822,787**
004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION Total					-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	3,111,263	3,111,263
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	174,543	174,543
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U1	31200	4.64%	104,845	104,845
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U2	31200	4.99%	127,429	127,429
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31100	2.52%	1,462,198	1,595,770
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31200	4.45%	94,329	94,329
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U1	31100	2.68%	261,417	261,417
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U2	31100	2.39%	85,078	85,078
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	42,091	42,091
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	2,292	2,292
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	898,111	898,111
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	584,290	584,290
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	133,479	133,479
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers U3 SC Peaker	34200	3.58%	18,616	18,616
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Martin Comm	34200	2.42%	455,941	455,941
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	PtEverglades GTs	34200	0.00%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	08 - General Plant	General Plant	39000	1.50%	5,837,840	5,837,840
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total					**13,393,764**	**13,527,336**
007-RELOCATE TURBINE LUBE OIL PIPING	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	31,030	31,030
007-RELOCATE TURBINE LUBE OIL PIPING Total					**31,030**	**31,030**
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	46,882	46,882
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31670	7-Year	54,241	21,347
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31600	3.79%	23,107	23,107
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31650	5-Year	-	116,547
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31670	7-Year	431,173	339,743
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31670	7-Year	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	363,996	363,996
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	Sanford Comm	34100	2.40%	15,922	15,922
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	2,995	2,995
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39000	1.50%	4,413	4,413
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39190	3-Year	6,398	2,291
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total					**949,127**	**937,244**
010-REROUTE STORMWATER RUNOFF	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	117,794	117,794
010-REROUTE STORMWATER RUNOFF Total					**117,794**	**117,794**
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	524,873	524,873
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31200	2.23%	328,762	328,762
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31400	2.08%	689	689
012-SCHERER DISCHARGE PIPELINE Total					**854,324**	**854,324**
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U1	31200	4.53%	367,906	367,906
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U2	31200	4.64%	403,671	403,671
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total					**771,577**	**771,577**
021-ST.LUCIE TURTLE NETS	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	6,909,559	6,909,559

021-ST.LUCIE TURTLE NETS Total					**6,909,559**	**6,909,559**
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	601,217	601,217
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Martin Comm	31100	2.52%	2,271,574	2,271,574
022-PIPELINE INTEGRITY MANAGEMENT Total					**2,872,791**	**2,872,791**
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	1,240,613	1,243,306
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	33,272	33,272
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31500	2.34%	26,325	26,325
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U1	31200	4.64%	45,750	45,750
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U2	31200	4.99%	37,431	37,431
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31100	2.52%	568,374	574,162
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31500	3.57%	34,755	34,755
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	712,225	712,225
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32400	3.20%	745,335	745,335
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U2	32300	3.86%	552,390	552,390
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	931,430	977,935
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	189,219	189,219
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	1,480,169	1,480,169
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34300	5.20%	28,250	28,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34100	4.18%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	513,250	513,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34100	7.40%	98,715	98,715
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	629,983	629,983
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34500	7.77%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U2	34300	3.46%	49,727	49,727
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U3 SC Peaker	34500	3.40%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin Comm	34100	2.24%	523,498	523,498
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin U8	34200	2.70%	84,868	84,868
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEvergladesComm	34200	2.90%	2,728,283	2,728,283
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEvergladesGTs	34100	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEvergladesGTs	34200	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEvergladesGTs	34500	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Sanford Comm	34100	2.40%	288,383	288,383
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Radial	35200	1.70%	6,946	6,946
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.70%	1,124,628	1,142,640
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	177,982	177,982
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35800	1.87%	65,655	65,655
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	3,169,685	3,298,168
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	70,499	70,499
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	08 - General Plant	General Plant	39000	1.50%	146,691	146,691
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total					**16,329,193**	**16,530,675**
024-GAS REBURN	02 - Steam Generation Plant	Manatee U1	31200	4.64%	16,304,833	16,304,710
024-GAS REBURN	02 - Steam Generation Plant	Manatee U2	31200	4.99%	15,277,025	15,277,025
024-GAS REBURN Total					**31,581,858**	**31,581,736**
026-UST REPLACEMENT/REMOVAL	08 - General Plant	General Plant	39000	1.50%	115,447	115,447
026-UST REPLACEMENT/REMOVAL Total					**115,447**	**115,447**
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	CapeCana Comm CC	34100	2.69%		766,645
028-CWA 316B PHASE II RULE Total						**766,645**
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	102,052	102,052
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31200	4.64%	20,059,060	20,059,060
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31400	4.03%	7,240,124	7,240,124
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31200	4.99%	20,461,529	20,461,529
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31400	3.72%	7,905,907	7,905,907
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31200	4.45%	518,275	518,275
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31400	3.48%	287,258	287,258
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31200	4.53%	19,504,077	19,504,077
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31400	3.35%	7,499,710	7,499,710
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31200	4.64%	20,248,975	20,224,580
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31400	4.79%	7,477,120	7,477,120
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	2,243,194	79,730
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31100	2.30%	82,366,984	82,366,984
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	254,248,896	254,475,936
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31400	1.89%	(94,224)	(94,224)
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31500	2.49%	19,615,426	19,615,426
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31600	1.88%	399,586	399,586
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31670	7-Year	12,775	12,775
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U1	31200	2.12%	27,744,107	27,746,239
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U1	31500	1.46%	446,692	446,692
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U1	31600	1.14%	9,138	9,138
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U2	31200	2.35%	26,534,954	26,534,954
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U2	31500	1.84%	426,220	426,220
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U2	31600	1.58%	9,591	9,591
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	110,242	110,242
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtMyers GTs	34300	8.22%	57,855	57,855
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34100	2.24%	763,350	699,143
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34300	2.56%	244,343	244,343
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34500	2.04%	292,499	292,499
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	PtEvergladesGTs	34300	0.00%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	2.57%	411,775	1,313
031-CLEAN AIR INTERSTATE RULE-CAIR Total					**527,147,489**	**524,714,132**
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	(1,234,033)	(1,234,039)
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	108,641,809	108,641,809
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	SJRPP U1	31200	2.12%	70,087	70,087
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	SJRPP U2	31200	2.35%	18,075	18,075
033-CLEAN AIR MERCURY RULE-CAMR Total					**107,495,938**	**107,495,932**
035-MARTIN PLANT DRINKING WATER COMP	02 - Steam Generation Plant	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	StLucie Comm	32100	2.25%	7,601,405	7,601,405
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	9,855,399	9,855,399
036-LOW LEV RADI WSTE-LLW Total					**17,456,804**	**17,456,804**

037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34000	0.00%	255,507	255,507
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34100	3.49%	5,265,937	5,264,052
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34300	3.36%	115,297,818	115,292,510
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34500	3.65%	26,746,246	26,746,246
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34630	3-Year	1,886	8,469
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34650	5-Year	36,693	50,315
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34670	7-Year	126,709	161,143
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	TransGeneratorLead	35300	2.04%	308,244	308,244
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.70%	7,427	7,427
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	695,782	695,782
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.64%	1,728,419	1,695,869
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.32%	394,418	394,418
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.38%	191,358	191,358
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	540,994	540,994
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	1,919,623	1,890,938
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	28,426	28,426
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year	21,238	-
037-DE SOTO SOLAR PROJECT Total					**153,566,725**	**153,531,698**
038-SPACE COAST SOLAR PROJECT	01 - Intangible Plant	Intangible Plant	30300	various	6,359,027	6,359,027
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34100	3.45%	3,893,856	3,889,496
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34300	3.30%	51,550,587	51,550,587
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34500	3.51%	6,126,699	6,126,699
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34630	3-Year	-	-
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	51,560	14,106
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	TransGeneratorLead	35300	2.04%	789,138	789,138
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	139,391	139,391
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.64%	1,328,699	1,328,699
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	274,858	274,858
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	62,689	62,689
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	31,858	31,858
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year	6,741	-
038-SPACE COAST SOLAR PROJECT Total					**70,650,306**	**70,601,750**
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34000	0.00%	216,844	216,844
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34100	2.99%	20,746,646	20,745,276
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34300	2.88%	395,612,998	397,113,924
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34500	2.99%	4,125,204	4,122,852
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34600	2.85%	1,299	1,299
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34650	5-Year	11,178	11,178
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34670	7-Year	81,460	134,433
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin U8	34300	3.37%	423,126	423,126
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.32%	603,692	603,692
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.38%	364,159	364,159
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36400	0.00%	9,282	-
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	1.42%	94,476	94,476
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	1.96%	2,728	2,728
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	121,101	121,101
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39240	2.63%	332,682	332,682
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39290	4.99%	88,938	88,938
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39420	7-Year	13,666	13,666
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year	4,442	4,442
039-MARTIN SOLAR PROJECT Total					**422,853,922**	**424,394,815**
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	0.00%	4,042,459	4,042,459
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	472,661	471,542
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36400	0.00%	225,952	-
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36410	various		137,247
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36420	various		36,431
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	various	307,599	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	16,244	-
041-PRV MANATEE HEATING SYSTEM Total					**5,805,515**	**5,735,878**
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	17,170,089	17,066,101
042-PTN COOLING CANAL MONITORING SYS Total					**17,170,089**	**17,066,101**
044-Barley Barber Swamp Iron Mitiga	02 - Steam Generation Plant	Martin Comm	31100	2.52%	164,719	164,719
044-Barley Barber Swamp Iron Mitiga Total					**164,719**	**164,719**
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	155,747	155,747
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31200	4.64%	44,989,219	44,989,219
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31500	4.11%	4,524,074	4,524,074
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31600	3.91%	1,021,918	1,021,918
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31200	4.99%	51,910,750	51,910,750
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31500	4.48%	4,793,798	4,793,798
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31600	4.79%	1,071,311	1,071,311
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31200	4.53%	47,161,912	47,137,592
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31500	3.12%	4,322,420	4,322,420
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31600	3.81%	1,006,508	1,012,007
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31200	4.64%	48,464,683	48,445,547
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31500	3.56%	4,449,156	4,449,270
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31600	4.31%	1,034,718	1,070,760
045-800 MW UNIT ESP PROJECT Total					**214,906,214**	**214,904,413**
054-Coal Combustion Residuals	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	200,216	204,391
054-Coal Combustion Residuals	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	54,373	56,167
054-Coal Combustion Residuals Total					**254,590**	**260,558**

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER 2017 TEST YEAR RATE CASE KO-20 EXHIBIT @ 10.55% ROE

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

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

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$9,420,954,129	39.05%	4.599%	1.796%	1.796%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	14,704,264,823	60.95%	10.550%	6.430%	10.468%
TOTAL	$24,125,218,952	100.00%		8.226%	12.264%
RATIO					

DEBT COMPONENTS:

LONG TERM DEBT	1.3349%
SHORT TERM DEBT	0.0314%
CUSTOMER DEPOSITS	0.0261%
TAX CREDITS -WEIGHTED	0.0060%
TOTAL DEBT	**1.3984%**

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	4.7794%
TAX CREDITS -WEIGHTED	0.0215%
TOTAL EQUITY	**4.8009%**
TOTAL	6.1993%
PRE-TAX EQUITY	7.8159%
PRE-TAX TOTAL	9.2143%

Note:

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

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.55%	**CAPITAL STRUCTURE AND COST RATES PER MAY 2017 EARNINGS SURVEILLANCE REPORT**				
	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	8,578,170,782	27.773%	4.53%	1.26%	1.26%
SHORT_TERM_DEBT	876,957,343	2.839%	1.76%	0.05%	0.05%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	421,323,778	1.364%	2.09%	0.03%	0.03%
COMMON_EQUITY	14,087,418,183	45.610%	10.55%	4.81%	7.83%
DEFERRED_INCOME_TAX	6,860,621,618	22.212%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	62,115,684	0.201%	8.27%	0.02%	0.02%
TOTAL	$30,886,607,389	100.00%		6.17%	9.20%

	CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)				
	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$8,578,170,782	37.85%	4.534%	1.716%	1.716%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	14,087,418,183	62.15%	10.550%	6.557%	10.675%
TOTAL	$22,665,588,966	100.00%		8.273%	12.391%
RATIO					

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

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

Note:

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

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

FORM: 42-1E

JANUARY 2018 THROUGH DECEMBER 2018

	2018
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($6,713,285)
2. Interest Provision (Form 42-2E, Line 6)	$1,098,865
3. Sum of Current Period Adjustments (Form 42-2E, Line 11)	$0
4. Actual/Estimated True-up to be refunded/(recovered)	($5,614,420)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 12
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Renae B. Deaton RBD-2

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

FORM: 42-2E

JANUARY 2018 THROUGH DECEMBER 2018

	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)	$12,072,440	$11,179,087	$11,069,185	$11,616,141	$12,931,992	$14,163,801	$11,862,466	$11,704,678	$11,647,471	$11,152,458	$9,167,287	$9,026,825	$137,593,830
2. True-up Provision [a]	$4,389,174	$4,389,174	$4,389,174	$4,389,174	$4,389,174	$4,389,174	$4,389,174	$4,389,174	$4,389,174	$4,389,174	$4,389,174	$4,389,174	$52,670,082
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$16,461,613	$15,568,260	$15,458,359	$16,005,315	$17,321,166	$18,552,974	$16,251,639	$16,093,851	$16,036,645	$15,541,631	$13,556,461	$13,415,998	$190,263,912
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5E-2, Line 9)	$2,578,339	$2,614,067	$3,001,947	$2,800,321	$2,970,802	$1,818,636	$5,455,398	$7,868,466	$4,594,770	$4,809,079	$5,077,149	$5,893,474	$49,482,448
b. Capital Investment Projects (Form 42-7E-2, Line 8)	$12,253,628	$12,235,249	$12,232,418	$12,235,253	$12,264,930	$12,348,808	$12,245,865	$12,267,744	$12,295,405	$12,319,144	$12,331,821	$12,464,483	$147,494,749
c. Total Jurisdictional ECRC Costs	$14,831,967	$14,849,316	$15,234,365	$15,035,574	$15,235,732	$14,167,444	$17,701,263	$20,136,210	$16,890,175	$17,128,223	$17,408,970	$18,357,957	$196,977,197
5. Over/(Under) Recovery (Line 3 - Line 4c)	$1,629,646	$718,944	$223,993	$969,741	$2,085,433	$4,385,530	($1,449,624)	($4,042,359)	($853,530)	($1,586,592)	($3,852,509)	($4,941,959)	($6,713,285)
6. Interest Provision (Form 42-3E, Line 10)	$104,944	$102,334	$110,091	$111,675	$107,714	$106,663	$102,277	$91,318	$80,805	$72,190	$61,225	$47,628	$1,098,865
7. Prior Periods True-Up to be (Collected)/Refunded	$52,670,082	$50,015,493	$46,447,592	$42,392,498	$39,084,735	$36,888,709	$36,991,729	$31,255,209	$22,914,995	$17,753,096	$11,849,521	$3,669,064	$52,670,082
a. Deferred True-Up (Form 42-1A, Line 7) [b]	$31,560,081	$31,560,081	$31,560,081	$31,560,081	$31,560,081	$31,560,081	$31,560,081	$31,560,081	$31,560,081	$31,560,081	$31,560,081	$31,560,081	
8. True-Up Collected /(Refunded) (See Line 2)	($4,389,174)	($4,389,174)	($4,389,174)	($4,389,174)	($4,389,174)	($4,389,174)	($4,389,174)	($4,389,174)	($4,389,174)	($4,389,174)	($4,389,174)	($4,389,174)	($52,670,082)
9. End of Period True-Up (Lines 5+6+7+7a+8)	$81,575,579	$78,007,678	$73,952,584	$70,644,821	$68,448,790	$68,551,810	$62,815,290	$54,475,075	$49,313,177	$43,409,602	$35,229,144	$25,945,641	($5,614,420)
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)	$81,575,579	$78,007,678	$73,952,584	$70,644,821	$68,448,790	$68,551,810	$62,815,290	$54,475,075	$49,313,177	$43,409,602	$35,229,144	$25,945,641	($5,614,420)

[a] As approved in Order No. PSC-2018-0014-FOF-EI issued January 5, 2018.

[b] From FPL's revised 2017 Final True-up filed on July 25, 2018.

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

FORM: 42-3E

JANUARY 2018 THROUGH DECEMBER 2018

	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)	$84,230,163	$81,575,574	$78,007,673	$73,952,579	$70,644,816	$68,448,790	$68,551,810	$62,815,290	$54,475,075	$49,313,177	$43,409,602	$35,229,144	
2. Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	$81,470,635	$77,905,344	$73,842,492	$70,533,146	$68,341,076	$68,445,147	$62,713,013	$54,383,758	$49,232,372	$43,337,412	$35,167,919	$25,898,012	
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$165,700,798	$159,480,918	$151,850,165	$144,485,724	$138,985,892	$136,893,937	$131,264,823	$117,199,048	$103,707,447	$92,650,589	$78,577,522	$61,127,157	
4. Average True-Up Amount (Line 3 x 1/2)	$82,850,399	$79,740,459	$75,925,082	$72,242,862	$69,492,946	$68,446,968	$65,632,411	$58,599,524	$51,853,724	$46,325,294	$39,288,761	$30,563,578	
5. Interest Rate (First Day of Reporting Month)	1.58000%	1.46000%	1.62000%	1.86000%	1.85000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	
6. Interest Rate (First Day of Subsequent Month)	1.46000%	1.62000%	1.86000%	1.85000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.04000%	3.08000%	3.48000%	3.71000%	3.72000%	3.74000%	3.74000%	3.74000%	3.74000%	3.74000%	3.74000%	3.74000%	
8. Average Interest Rate (Line 7 x 1/2)	1.52000%	1.54000%	1.74000%	1.85500%	1.86000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	1.87000%	
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.12667%	0.12833%	0.14500%	0.15458%	0.15500%	0.15583%	0.15583%	0.15583%	0.15583%	0.15583%	0.15583%	0.15583%	
10. Interest Provision for the Month (Line 4 x Line 9)	$104,944	$102,334	$110,091	$111,675	$107,714	$106,663	$102,277	$91,318	$80,805	$72,190	$61,225	$47,628	$1,098,865

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

FORM: 42-4E-1

JANUARY 2018 THROUGH DECEMBER 2018
VARIANCE REPORT OF O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)
PROJECT #	ECRC - 2018 Actual Estimated Filing [a]	ECRC - 2018 Tax Act Midcourse Correction [b]	Dif ECRC - 2018 Tax Act Midcourse Correction [c]	% Dif ECRC - 2018 Tax Act Midcourse Correction [d]
1 - Air Operating Permit Fees	$287,797	$262,779	$25,018	10%
3 - Continuous Emission Monitoring Systems	$337,938	$373,745	($35,807)	(10%)
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$699,377	$1,793,246	($1,093,869)	(61%)
8 - Oil Spill Clean-up/Response Equipment	$273,045	$273,314	($269)	(0%)
14 - NPDES Permit Fees	$69,200	$69,000	$200	0%
17a - Disposal of Non-Containerized Liquid Waste	$0	$5,000	($5,000)	(100%)
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$2,619,748	$2,675,270	($55,522)	(2%)
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$1,066,231	$987,940	$78,291	8%
21 - St. Lucie Turtle Nets	$103,420	$110,000	($6,580)	(6%)
NA-Amortization of Gains on Sales of Emissions Allowances	($339)	($339)	($0)	0%
22 - Pipeline Integrity Management	$80,476	$586,000	($505,524)	(86%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$890,752	$846,140	$44,612	5%
24 - Manatee Reburn	$116,892	$125,976	($9,084)	(7%)
27 - Lowest Quality Water Source	$142,896	$156,000	($13,104)	(8%)
28 - CWA 316(b) Phase II Rule	$1,441,646	$1,526,115	($84,469)	(6%)
29 - SCR Consumables	$532,480	$717,092	($184,612)	(26%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$4,797,154	$4,889,561	($92,407)	(2%)
33 - MATS Project	$2,395,698	$2,395,698	$0	0%
35 - Martin Plant Drinking Water System Compliance	$36,715	$35,804	$911	3%
37 - DeSoto Next Generation Solar Energy Center	$575,861	$609,729	($33,868)	(6%)
38 - Space Coast Next Generation Solar Energy Center	$391,873	$379,604	$12,270	3%
39 - Martin Next Generation Solar Energy Center	$4,325,647	$3,487,793	$837,854	24%
41 - Manatee Temporary Heating System	$663,434	$678,100	($14,666)	(2%)
42 - Turkey Point Cooling Canal Monitoring Plan	$28,268,375	$18,804,919	$9,463,456	50%
45 - 800 MW Unit ESP	$752,395	$823,181	($70,786)	(9%)
47 - NPDES Permit Renewal Requirements	$487,554	$298,198	$189,356	64%
48 - Industrial Boiler MACT	$17,000	$23,000	($6,000)	(26%)
50 - Steam Electric Effluent Guidelines Revised Rules	$295,500	$295,500	$0	0%
51 - Gopher Tortoise Relocations	$24,649	$24,649	$0	0%
54 - Coal Combustion Residuals	$0	$0	$0	0%
55 - Solar Site Avian Monitoring and Reporting	$69,777	$0	$69,777	N/A
Total	$51,763,189	$43,253,012	$8,510,177	20%

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

[b] As approved in Order No. PSC-2018-0014-FOF-EI issued January 5, 2018.

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

[d] 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 2018 THROUGH DECEMBER 2018

(1)	(2)	(3)	(4)	(5)
	ECRC - 2018 Actual Estimated Filing [a]	ECRC - 2018 Tax Act Midcourse Correction [b]	Dif ECRC - 2018 Tax Act Midcourse Correction [c]	% Dif ECRC - 2018 Tax Act Midcourse Correction [d]
2. Total of O&M Activities	$51,763,189	$43,253,012	$8,510,177	20%
3. Recoverable Costs Allocated to Energy	$38,424,867	$29,349,025	$9,075,842	31%
4a. Recoverable Costs Allocated to CP Demand	$10,718,574	$11,228,717	($510,143)	(5%)
4b. Recoverable Costs Allocated to GCP Demand	$2,619,748	$2,675,270	($55,522)	(2%)
5. Jurisdictional Energy Recoverable Costs	$36,764,141	$28,067,306	$8,696,835	31%
6a. Jurisdictional CP Demand Recoverable Costs	$10,098,559	$10,583,891	($485,332)	(5%)
6b. Jurisdictional GCP Demand Recoverable Costs	$2,619,748	$2,675,270	($55,522)	(2%)
7. Total Jurisdictional Recoverable Costs for O&M Activities	$49,482,448	$41,326,467	$8,155,980	20%

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

[b] As approved in Order No. PSC-2018-0014-FOF-EI issued January 5, 2018.

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

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

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

JANUARY 2018 THROUGH DECEMBER 2018
O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
O&M Project	Strata	January Actual	February Actual	March Actual	April Actual	May Actual	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1 - Air Operating Permit Fees	Base	$11,135	$11,135	$11,135	$11,135	$11,135	$11,135	$11,940	$11,250	$11,250	$11,250	$11,250	$11,250	$135,000
1 - Air Operating Permit Fees	Intermediate	$6,652	$8,183	$22,674	$8,039	$8,039	$8,038	$8,038	$8,038	$8,038	$8,038	$8,038	$8,038	$109,855
1 - Air Operating Permit Fees	Peaking	$3,853	$4,564	($6,561)	$4,564	$4,564	$4,565	$4,565	$4,565	$4,565	$4,565	$4,565	$4,565	$42,942
3 - Continuous Emission Monitoring Systems	Intermediate	$24,019	$8,074	$43,465	$7,164	$17,484	$17,950	$20,479	$17,950	$17,950	$17,950	$17,950	$41,710	$252,148
3 - Continuous Emission Monitoring Systems	Peaking	$5,192	$2,743	$5,655	$1,809	$24,603	$6,513	$6,498	$5,527	$4,846	$4,831	$4,846	$12,728	$85,790
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$0	$0	($1,850)	($27,412)	$0	$116,161	$226,799	$0	$75,000	$25,000	$0	$0	$413,697
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$99,755	$17,699	($105,919)	($26,029)	$6,470	$90,764	$202,939	$0	$0	$0	$0	$0	$285,680
8 - Oil Spill Clean-up/Response Equipment	Base	$2	($98)	$0	$53	$0	$0	$0	$0	$0	$0	$0	$0	($43)
8 - Oil Spill Clean-up/Response Equipment	Intermediate	$1,054	$1,644	$994	$4,411	$1,409	$2,200	$2,200	$3,850	$2,750	$3,300	$4,053	$2,200	$30,065
8 - Oil Spill Clean-up/Response Equipment	Peaking	$8,539	$12,788	$8,042	$35,965	$11,400	$17,800	$17,800	$31,150	$22,250	$26,700	$32,790	$17,800	$243,023
14 - NPDES Permit Fees	Base	$11,500	$0	$2,560	($2,560)	$0	$0	$0	$0	$0	$0	$0	$0	$11,500
14 - NPDES Permit Fees	Intermediate	$28,260	$0	$13,500	($13,500)	$0	$0	$0	$0	$0	$0	$0	$0	$28,260
14 - NPDES Permit Fees	Peaking	$29,440	$0	$0	$7,500	($7,500)	$0	$0	$0	$0	$0	$0	$0	$29,440
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$142,268	$170,484	$257,200	$273,496	$338,379	$219,352	$219,352	$185,843	$195,843	$205,843	$205,843	$205,843	$2,619,748
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$29,940	$49,767	$396,521	$146,109	$81,708	$49,938	$49,938	$54,425	$54,425	$46,314	$57,251	$49,895	$1,066,231
21 - St. Lucie Turtle Nets	Base	($6,580)	$0	$0	$0	$0	$0	$30,000	$16,000	$16,000	$16,000	$16,000	$16,000	$103,420
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($4)	($4)	($4)	($4)	($4)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($219)
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	($16)	($16)	($16)	($16)	($16)	$0	$0	$0	$0	$0	$0	$0	($80)
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	($8)	($8)	($8)	($8)	($8)	$0	$0	$0	$0	$0	$0	$0	($40)
22 - Pipeline Integrity Management	Intermediate	$0	$2,115	($5,270)	($18,539)	$0	$5,355	$14,621	$14,621	$14,622	$5,355	$5,355	$5,355	$43,589
22 - Pipeline Integrity Management	Peaking	$0	$2,983	($7,431)	($26,141)	$0	$4,040	$17,106	$17,105	$17,106	$4,040	$4,040	$4,040	$36,887
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$47,588	$45,406	$36,825	$39,318	$52,503	$50,588	$58,812	$91,357	$80,942	$50,607	$51,293	$51,311	$656,548
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$4,684	$4,851	$2,521	$1,376	$596	$1,931	$2,128	$2,797	$3,163	$2,597	$2,586	$3,865	$33,095
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$4,654	$7,050	$3,327	$3,100	$5,728	$1,654	$1,753	$1,593	$1,549	$1,593	$1,578	$2,280	$35,859
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$12,388	$11,464	$9,847	$10,865	$12,936	$18,250	$13,250	$18,250	$13,250	$18,250	$13,250	$13,250	$165,250
24 - Manatee Reburn	Peaking	$0	$5	$3,950	($38,706)	$3,240	$45,000	$44,370	$0	$0	$0	$59,033	$0	$116,892
27 - Lowest Quality Water Source	Intermediate	$11,366	$11,098	$12,014	$11,777	$10,771	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$13,870	$142,896
28 - CWA 316(b) Phase II Rule	Base	$12,410	$18,038	$16,356	$16,120	$4,557	$13,076	$13,103	$13,129	$16,599	$15,735	$13,103	$13,076	$165,301
28 - CWA 316(b) Phase II Rule	Intermediate	$42,581	$134,478	$92,062	$73,629	$83,024	$109,019	$82,285	$104,236	$101,327	$88,280	$77,469	$114,056	$1,102,447
28 - CWA 316(b) Phase II Rule	Peaking	$10,854	$16,079	$14,786	$9,862	$13,533	$23,382	$18,390	$14,754	$14,357	$14,754	$14,545	$8,602	$173,898
29 - SCR Consumables	Intermediate	$20,484	$47,106	$19,491	$19,543	$19,949	$45,411	$56,013	$58,477	$46,772	$61,344	$69,259	$68,631	$532,480
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$401,481	$332,370	$364,911	$607,589	$614,702	($283,052)	$577,282	$374,739	$399,250	$363,661	$293,544	$283,633	$4,330,111
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$16,507	$44,679	$25,865	$29,064	$25,567	$77,175	$40,545	$40,545	$40,545	$40,545	$40,545	$45,462	$467,043
33 - MATS Project	Base	$157,019	$119,927	$84,969	$46,910	$86,816	$39,820	$738,123	$230,289	$237,844	$215,446	$218,191	$220,342	$2,395,698
35 - Martin Plant Drinking Water System Compliance	Peaking	$0	$7,500	$2,553	$5,722	$53	$2,983	$2,983	$2,983	$2,983	$2,983	$2,983	$2,987	$36,715
37 - DeSoto Next Generation Solar Energy Center	Solar	$35,050	$29,342	$42,163	$24,586	$29,719	$31,693	$35,986	$36,219	$120,034	$56,704	$70,402	$63,962	$575,861
38 - Space Coast Next Generation Solar Energy Center	Solar	$26,515	$40,327	$18,299	$15,600	$57,299	$52,072	$33,401	$30,599	$27,766	$27,287	$31,266	$31,442	$391,873
39 - Martin Next Generation Solar Energy Center	Intermediate	$428,249	$413,861	$291,951	$320,185	$325,591	$282,218	$256,353	$252,488	$247,083	$623,074	$627,111	$257,483	$4,325,647
41 - Manatee Temporary Heating System	Intermediate	$287	$1,944	$35,048	$43,774	$14,042	$25,000	$160,958	$118,000	$198,282	$0	$0	$0	$597,334
41 - Manatee Temporary Heating System	Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,200	$22,700	$23,200	$66,100
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$1,018,514	$1,000,284	$1,389,114	$1,209,272	$1,146,693	$702,723	$2,708,586	$6,184,964	$2,638,185	$2,707,876	$3,157,192	$4,404,973	$28,268,375
45 - 800 MW Unit ESP	Peaking	$33,154	$66,540	$47,593	$52,504	$26,341	$48,150	$49,612	$51,074	$46,688	$208,193	$64,111	$58,434	$752,395
47 - NPDES Permit Renewal Requirements	Base	$0	$0	$0	$39,946	$54,374	$20,833	$120,833	$120,833	$20,833	$20,833	$20,833	$20,837	$440,155
47 - NPDES Permit Renewal Requirements	Intermediate	$472	$0	$8,043	($1,310)	$0	$7,250	$5,121	$0	$10,554	$6,981	$418	$0	$37,529
47 - NPDES Permit Renewal Requirements	Peaking	$601	$0	$3,087	($874)	$0	$0	$3,528	$0	$3,528	$0	$0	$0	$9,870
48 - Industrial Boiler MACT	Base	$557	$86	$0	$0	$412	$0	$0	$0	$0	$1,665	$0	$0	$2,720
48 - Industrial Boiler MACT	Peaking	$2,924	$451	$0	$0	$2,162	$0	$0	$0	$0	$8,744	$0	$0	$14,280
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$15,318	$92,029	$328	$3,337	$12,563	$25,000	$23,801	$24,625	$24,625	$24,625	$24,625	$24,625	$295,500
51 - Gopher Tortoise Relocations	Intermediate	$0	$0	$0	$0	$0	$0	$2,000	$0	$0	$0	$0	$0	$2,000
51 - Gopher Tortoise Relocations	Peaking	$0	$0	$0	$0	$0	$0	$0	$14,649	$0	$8,000	$0	$0	$22,649
54 - Coal Combustion Residuals	Base	$0	$0	$0	$0	$0	$0	($189,700)	$37,940	$37,940	$37,940	$37,940	$37,940	$0
55 - Solar Site Avian Monitoring and Reporting	Solar	$0	$0	$0	$0	$0	$0	$2,860	$13,383	$13,383	$13,383	$13,383	$13,383	$69,777
	Total	$2,698,662	$2,736,967	$3,159,790	$2,929,223	$3,100,833	$1,905,959	$5,706,621	$8,220,220	$4,804,101	$5,032,459	$5,311,313	$6,157,041	$51,763,189

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

JANUARY 2018 THROUGH DECEMBER 2018
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	$135,000	95.7811%	$129,304	$129,304	$0	$0
1 - Air Operating Permit Fees	Intermediate	$109,855	94.2579%	$103,547	$103,547	$0	$0
1 - Air Operating Permit Fees	Peaking	$42,942	94.8545%	$40,732	$40,732	$0	$0
3 - Continuous Emission Monitoring Systems	Intermediate	$252,148	94.2579%	$237,670	$237,670	$0	$0
3 - Continuous Emission Monitoring Systems	Peaking	$85,790	94.8545%	$81,375	$81,375	$0	$0
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$413,697	94.1431%	$389,467	$0	$389,467	$0
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$285,680	94.7386%	$270,649	$0	$270,649	$0
8 - Oil Spill Clean-up/Response Equipment	Base	($43)	95.7811%	($41)	($41)	$0	$0
8 - Oil Spill Clean-up/Response Equipment	Intermediate	$30,065	94.2579%	$28,338	$28,338	$0	$0
8 - Oil Spill Clean-up/Response Equipment	Peaking	$243,023	94.8545%	$230,519	$230,519	$0	$0
14 - NPDES Permit Fees	Base	$11,500	95.6652%	$11,001	$0	$11,001	$0
14 - NPDES Permit Fees	Intermediate	$28,260	94.1431%	$26,605	$0	$26,605	$0
14 - NPDES Permit Fees	Peaking	$29,440	94.7386%	$27,891	$0	$27,891	$0
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	Distribution	$2,619,748	100.0000%	$2,619,748	$0	$0	$2,619,748
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	Transmission	$1,066,231	88.7974%	$946,785	$0	$946,785	$0
21 - St. Lucie Turtle Nets	Base	$103,420	95.6652%	$98,937	$0	$98,937	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($219)	95.7811%	($210)	($210)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Intermediate	($80)	94.2579%	($75)	($75)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Peaking	($40)	94.8545%	($38)	($38)	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Distribution	$0	100.0000%	$0	$0	$0	$0
22 - Pipeline Integrity Management	Intermediate	$43,589	94.1431%	$41,036	$0	$41,036	$0
22 - Pipeline Integrity Management	Peaking	$36,887	94.7386%	$34,946	$0	$34,946	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$33,095	94.1431%	$31,156	$0	$31,156	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$35,859	94.7386%	$33,972	$0	$33,972	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$656,548	100.0000%	$656,548	$0	$656,548	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$165,250	88.7974%	$146,738	$0	$146,738	$0
24 - Manatee Reburn	Peaking	$116,892	94.8545%	$110,877	$110,877	$0	$0
27 - Lowest Quality Water Source	Intermediate	$142,896	94.1431%	$134,526	$0	$134,526	$0
28 - CWA 316(b) Phase II Rule	Base	$165,301	95.6652%	$158,136	$0	$158,136	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$1,102,447	94.1431%	$1,037,877	$0	$1,037,877	$0
28 - CWA 316(b) Phase II Rule	Peaking	$173,898	94.7386%	$164,748	$0	$164,748	$0
29 - SCR Consumables	Intermediate	$532,480	94.2579%	$501,904	$501,904	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$4,330,111	95.7811%	$4,147,428	$4,147,428	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$0	94.2579%	$0	$0	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$467,043	94.8545%	$443,011	$443,011	$0	$0
33 - MATS Project	Base	$2,395,698	95.7811%	$2,294,626	$2,294,626	$0	$0
35 - Martin Plant Drinking Water System Compliance	Peaking	$36,715	94.7386%	$34,783	$0	$34,783	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$575,861	95.6652%	$550,899	$0	$550,899	$0
38 - Space Coast Next Generation Solar Energy Center	Solar	$391,873	95.6652%	$374,887	$0	$374,887	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$4,325,647	94.1431%	$4,072,298	$0	$4,072,298	$0
41 - Manatee Temporary Heating System	Intermediate	$597,334	94.2579%	$563,035	$563,035	$0	$0
41 - Manatee Temporary Heating System	Peaking	$66,100	94.8545%	$62,699	$62,699	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$28,268,375	95.7811%	$27,075,760	$27,075,760	$0	$0
45 - 800 MW Unit ESP	Peaking	$752,395	94.8545%	$713,680	$713,680	$0	$0
47 - NPDES Permit Renewal Requirements	Base	$440,155	95.6652%	$421,075	$0	$421,075	$0
47 - NPDES Permit Renewal Requirements	Intermediate	$37,529	94.1431%	$35,331	$0	$35,331	$0
47 - NPDES Permit Renewal Requirements	Peaking	$9,870	94.7386%	$9,351	$0	$9,351	$0
48 - Industrial Boiler MACT	Base	$2,720	95.6652%	$2,602	$0	$2,602	$0
48 - Industrial Boiler MACT	Peaking	$14,280	94.7386%	$13,529	$0	$13,529	$0
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$295,500	95.6652%	$282,691	$0	$282,691	$0
51 - Gopher Tortoise Relocations	Intermediate	$2,000	94.1431%	$1,883	$0	$1,883	$0
51 - Gopher Tortoise Relocations	Peaking	$22,649	94.7386%	$21,457	$0	$21,457	$0
52 - Numeric Nutrient Criteria Water Quality Standards in Florida	Intermediate	$0	94.1431%	$0	$0	$0	$0
54 - Coal Combustion Residuals	Base	$0	95.6652%	$0	$0	$0	$0
55 - Solar Site Avian Monitoring and Reporting	Solar	$69,777	95.6652%	$66,752	$0	$66,752	$0
	Total	$51,763,189		$49,482,448	$36,764,141	$10,098,558	$2,619,748

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

FORM: 42-5E-2

JANUARY 2018 THROUGH DECEMBER 2018
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	2018
2. Total of O&M Activities	$2,698,662	$2,736,967	$3,159,790	$2,929,223	$3,100,833	$1,905,959	$5,706,621	$8,220,220	$4,804,101	$5,032,459	$5,311,313	$6,157,041	$51,763,189
3. Recoverable Costs Jurisdictionalized on Energy - Base	$1,588,148	$1,463,614	$1,850,124	$1,874,955	$1,859,342	$470,599	$4,035,903	$6,801,214	$3,286,501	$3,298,204	$3,680,148	$4,920,170	$35,128,921
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$52,480	$66,935	$121,656	$82,915	$60,908	$98,600	$247,688	$206,315	$273,793	$90,632	$99,301	$120,580	$1,521,802
Recoverable Costs Jurisdictionalized on Energy - Peaking	$67,237	$131,310	$84,536	$85,191	$95,706	$199,203	$163,391	$132,862	$118,894	$305,034	$228,590	$162,189	$1,774,144
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$42,329	$61,231	$406,368	$156,974	$94,644	$68,188	$63,188	$72,675	$67,675	$64,564	$70,501	$63,145	$1,231,481
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$33,206	$110,152	$19,244	$56,842	$71,906	$58,909	($1,964)	$212,527	$115,997	$116,799	$112,501	$112,478	$1,018,597
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$515,612	$566,403	$412,970	$346,205	$419,982	$533,934	$601,307	$386,142	$463,749	$763,288	$724,939	$394,629	$6,129,159
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$148,229	$51,762	($89,596)	($26,859)	$20,446	$122,823	$246,699	$51,084	$39,524	$40,113	$23,146	$17,908	$645,278
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$61,565	$69,669	$60,462	$40,186	$87,018	$83,765	$72,247	$80,202	$161,184	$97,375	$115,052	$108,788	$1,037,511
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$47,588	$45,406	$36,825	$39,318	$52,503	$50,588	$58,812	$91,357	$80,942	$50,607	$51,293	$51,311	$656,548
5. Recoverable Costs Allocated to GCP Demand - Distribution	$142,268	$170,484	$257,200	$273,496	$338,379	$219,352	$219,352	$185,843	$195,843	$205,843	$205,843	$205,843	$2,619,748
6. Retail Production Energy Jurisdictional Factor - Base	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	
Retail Production Energy Jurisdictional Factor - Intermediate	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	
Retail Production Energy Jurisdictional Factor - Peaking	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	
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	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	
Retail Production Demand Jurisdictional Factor - Base	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	
Retail Production Demand Jurisdictional Factor - Intermediate	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	
Retail Production Demand Jurisdictional Factor - Peaking	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	
Retail Production Demand Jurisdictional Factor - Solar	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	
8. Jurisdictional Recoverable Costs- Transmission	$37,587	$54,372	$360,844	$139,389	$84,041	$60,549	$56,109	$64,533	$60,093	$57,331	$62,603	$56,072	$1,093,523
Jurisdictional Recoverable Costs - Production - Base	$1,552,912	$1,507,243	$1,790,479	$1,850,231	$1,849,687	$507,100	$3,863,754	$6,717,592	$3,258,816	$3,270,792	$3,632,511	$4,820,195	$34,621,310
Jurisdictional Recoverable Costs - Production - Interm.	$534,880	$596,321	$503,453	$404,082	$452,795	$595,600	$799,554	$557,995	$694,659	$804,011	$776,078	$485,172	$7,204,599
Jurisdictional Recoverable Costs - Production - Peaking	$204,207	$173,592	($4,696)	$55,362	$110,152	$305,314	$388,702	$174,422	$150,220	$327,342	$238,756	$170,810	$2,294,183
Jurisdictional Recoverable Costs - Production - Solar	$58,896	$66,649	$57,841	$38,444	$83,246	$80,134	$69,115	$76,725	$154,197	$93,154	$110,065	$104,072	$992,537
Jurisdictional Recoverable Costs - Distribution	$189,857	$215,891	$294,025	$312,814	$390,882	$269,940	$278,164	$277,200	$276,785	$256,450	$257,136	$257,154	$3,276,296
9. Total Jurisdictional Recoverable Costs for O&M Activities	$2,578,339	$2,614,067	$3,001,947	$2,800,321	$2,970,802	$1,818,636	$5,455,398	$7,868,466	$4,594,770	$4,809,079	$5,077,149	$5,893,474	$49,482,448

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

FORM: 42-6E

JANUARY 2018 THROUGH DECEMBER 2018
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE CO

Capital Project #	ECRC - 2018 Actual Estimated Filing [a]	ECRC - 2018 Tax Act Midcourse Correction [b]	Dif ECRC - 2018 Tax Act Midcourse Correction [c]	% Dif ECRC - 2018 Tax Act Midcourse Correction [d]
02 - Low NOX Burner Technology	$62,269	$62,515	($245)	(0%)
03 - Continuous Emission Monitoring Systems	$596,293	$677,393	($81,100)	(12%)
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,672,922	$1,581,779	$91,143	6%
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,782	$1,784	($1)	(0%)
08 - Oil Spill Clean-up/Response Equipment	$152,108	$154,970	($2,863)	(2%)
10 - Relocate Storm Water Runoff	$6,513	$6,552	($39)	(1%)
12 - Scherer Discharge Pipeline	$35,530	$35,735	($205)	(1%)
20 - Wastewater Discharge Elimination & Reuse	$77,613	$78,039	($425)	(1%)
21 - St. Lucie Turtle Nets	$740,606	$746,567	($5,961)	(1%)
22 - Pipeline Integrity Management	$269,328	$302,566	($33,237)	(11%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$2,135,454	$2,324,646	($189,192)	(8%)
24 - Manatee Reburn	$3,150,126	$3,163,850	($13,724)	(0%)
26 - UST Remove/Replacement	$6,764	$6,816	($51)	(1%)
28 - CWA 316(b) Phase II Rule	$78,782	$204,595	($125,813)	(61%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$48,156,194	$48,752,510	($596,317)	(1%)
33 - MATS Project	$9,606,375	$9,804,857	($198,481)	(2%)
34 - St Lucie Cooling Water System Inspection & Maintenance	$347,643	$449,061	($101,418)	(23%)
35 - Martin Plant Drinking Water System Compliance	$20,466	$20,614	($148)	(1%)
36 - Low-Level Radioactive Waste Storage	$1,690,444	$1,702,750	($12,305)	(1%)
37 - DeSoto Next Generation Solar Energy Center	$12,719,862	$12,787,121	($67,259)	(1%)
38 - Space Coast Next Generation Solar Energy Center	$5,903,927	$5,944,853	($40,925)	(1%)
39 - Martin Next Generation Solar Energy Center	$35,389,515	$35,663,181	($273,666)	(1%)
41 - Manatee Temporary Heating System	$478,899	$689,340	($210,440)	(31%)
42 - Turkey Point Cooling Canal Monitoring Plan	$4,504,185	$6,295,671	($1,791,486)	(28%)
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$14,919	$15,029	($110)	(1%)
45 - 800 MW Unit ESP	$24,103,096	$24,226,284	($123,188)	(1%)
54 - Coal Combustion Residuals	$3,243,328	$2,951,528	$291,800	10%
NA-Amortization of Gains on Sales of Emissions Allowances	($57)	($911)	$854	(94%)
Total Investment Projects - Recoverable Costs	$155,164,887	$158,649,692	($3,484,805)	(2%)

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

[b] The approved projected amount in accordance with FPSC Order No. PSC-2018-0100-FOF-EI issued February 22, 2018.

[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 2017 THROUGH DECEMBER 2017
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

	ECRC - 2018 Actual Estimated Filing [a]	ECRC - 2018 Tax Act Midcourse Correction [b]	Dif ECRC - 2018 Tax Act Midcourse Correction [c]	% Dif ECRC - 2018 Tax Act Midcourse Correction [d]
2. Total Investment Projects - Recoverable Costs	$155,164,887	$158,649,692	($3,484,805)	(2%)
3. Recoverable Costs Allocated to Energy	$3,808,631	$3,902,846	($94,215)	(2%)
4. Recoverable Costs Allocated to Demand	$151,356,256	$154,746,846	($3,390,590)	(2%)
5. Jurisdictional Energy Recoverable Costs	$134,573,499	$13,249,733	$121,323,766	916%
6. Jurisdictional Demand Recoverable Costs	$12,921,249	$137,555,599	($124,634,350)	(91%)
7. Total Jurisdictional Recoverable Costs for Investment Projects	$147,494,749	$150,805,332	($3,310,583)	(2%)

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

[b] As approved in Order No. PSC-2018-0100-FOF-EI issued February 22, 2018.

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

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

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

JANUARY 2018 THROUGH DECEMBER 2018
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	Total
02 - Low NOX Burner Technology	Peaking	$5,322	$5,301	$5,281	$5,260	$5,240	$5,220	$5,157	$5,137	$5,118	$5,098	$5,078	$5,058	$62,269
03 - Continuous Emission Monitoring Systems	Base	$2,508	$2,501	$2,493	$2,485	$2,477	$2,469	$2,436	$2,428	$2,421	$2,413	$2,405	$2,398	$29,434
03 - Continuous Emission Monitoring Systems	Intermediate	$26,861	$26,770	$26,677	$26,572	$26,467	$28,487	$30,374	$30,444	$30,343	$30,242	$30,140	$30,039	$343,416
03 - Continuous Emission Monitoring Systems	Peaking	$18,782	$18,717	$18,652	$18,587	$18,522	$18,457	$18,528	$18,770	$18,705	$18,640	$18,575	$18,510	$223,443
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$147	$147	$147	$147	$147	$147	$144	$144	$144	$144	$144	$144	$1,740
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$50,897	$50,850	$51,356	$51,862	$51,814	$51,767	$50,819	$50,772	$50,726	$50,679	$50,633	$51,419	$613,592
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$21,267	$21,202	$21,137	$21,070	$21,004	$20,939	$20,653	$20,590	$20,526	$20,462	$20,398	$20,334	$249,580
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$68,974	$68,730	$68,487	$68,242	$67,997	$67,754	$66,901	$66,662	$66,424	$66,185	$65,946	$65,708	$808,010
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$153	$153	$152	$151	$150	$149	$148	$147	$146	$145	$145	$144	$1,782
08 - Oil Spill Clean-up/Response Equipment	Distribution	$23	$23	$23	$23	$23	$23	$22	$22	$22	$22	$22	$22	$268
08 - Oil Spill Clean-up/Response Equipment	General	$93	$93	$92	$60	$28	$28	$27	$27	$27	$27	$27	$27	$558
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$7,268	$7,242	$7,217	$7,191	$7,165	$7,140	$7,050	$7,025	$6,893	$7,187	$7,556	$7,497	$86,430
08 - Oil Spill Clean-up/Response Equipment	Peaking	$5,471	$5,450	$5,430	$5,409	$5,388	$5,367	$5,155	$5,283	$5,182	$5,403	$5,679	$5,634	$64,852
10 - Relocate Storm Water Runoff	Base	$554	$552	$551	$550	$548	$547	$539	$537	$536	$534	$533	$532	$6,513
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($4)	($4)	($4)	($4)	($57)
12 - Scherer Discharge Pipeline	Base	$3,023	$3,015	$3,007	$2,999	$2,990	$2,982	$2,939	$2,931	$2,923	$2,915	$2,907	$2,899	$35,530
20 - Wastewater Discharge Elimination & Reuse	Peaking	$6,609	$6,590	$6,570	$6,551	$6,532	$6,513	$6,422	$6,403	$6,384	$6,365	$6,347	$6,328	$77,613
21 - St. Lucie Turtle Nets	Base	$62,677	$62,593	$62,509	$62,425	$62,340	$62,256	$61,174	$61,091	$61,009	$60,926	$60,844	$60,761	$740,606
22 - Pipeline Integrity Management	Intermediate	$12,227	$12,205	$12,183	$12,161	$12,139	$12,117	$11,918	$11,897	$11,875	$11,854	$11,832	$11,811	$144,221
22 - Pipeline Integrity Management	Peaking	$10,608	$10,589	$10,569	$10,550	$10,530	$10,511	$10,339	$10,320	$10,301	$10,282	$10,263	$10,244	$125,108
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$25,622	$25,561	$25,500	$27,662	$29,881	$29,868	$29,433	$29,355	$29,276	$29,198	$29,120	$29,042	$339,517
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$21,252	$21,237	$21,204	$21,172	$21,140	$21,108	$20,749	$20,717	$20,696	$20,693	$20,690	$20,678	$251,336
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$921	$920	$919	$917	$916	$915	$899	$898	$897	$895	$894	$893	$10,884
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$59,866	$59,715	$59,564	$59,413	$59,262	$59,131	$58,255	$58,107	$57,959	$57,944	$58,062	$58,047	$705,323
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$47,754	$47,589	$47,425	$47,261	$47,097	$46,932	$46,332	$46,171	$46,010	$46,678	$47,533	$47,560	$564,342
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$13,448	$13,542	$14,303	$15,324	$16,808	$19,470	$21,053	$23,686	$26,202	$30,460	$33,820	$35,937	$264,052
24 - Manatee Reburn	Intermediate	$0	$0	$0	$0	$0	$191	$375	$375	$375	$375	$561	$748	$3,001
24 - Manatee Reburn	Peaking	$267,640	$266,816	$265,997	$265,177	$264,354	$263,873	$260,701	$259,973	$259,164	$258,356	$257,810	$257,264	$3,147,124
25 - Pt. Everglades ESP Technology	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26 - UST Remove/Replacement	General	$573	$572	$571	$570	$569	$568	$559	$558	$557	$556	$555	$554	$6,764
28 - CWA 316(b) Phase II Rule	Intermediate	$6,673	$6,661	$6,652	$6,643	$6,632	$6,621	$6,511	$6,500	$6,489	$6,478	$6,467	$6,456	$78,782
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,086,330	$3,081,301	$3,076,236	$3,071,635	$3,067,419	$3,065,060	$3,016,881	$3,012,489	$3,007,449	$3,002,408	$2,997,368	$2,992,626	$36,477,202
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$9	$106
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$10,275	$10,256	$10,237	$10,219	$10,200	$10,181	$10,015	$9,996	$9,978	$9,959	$9,941	$9,922	$121,179
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$983,602	$980,881	$978,161	$975,440	$972,719	$969,999	$956,148	$953,483	$950,817	$948,152	$945,486	$942,821	$11,557,707
33 - MATS Project	Base	$807,947	$806,320	$804,961	$806,901	$809,089	$808,695	$797,030	$795,984	$794,390	$792,796	$791,201	$791,062	$9,606,375
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$29,257	$29,257	$29,257	$29,264	$29,271	$29,271	$28,678	$28,678	$28,678	$28,678	$28,678	$28,678	$347,643
35 - Martin Plant Drinking Water System Compliance	Intermediate	$989	$987	$986	$984	$982	$980	$964	$962	$961	$959	$957	$955	$11,666
35 - Martin Plant Drinking Water System Compliance	Peaking	$746	$745	$744	$742	$741	$739	$727	$726	$725	$723	$722	$721	$8,801
36 - Low-Level Radioactive Waste Storage	Base	$143,325	$143,065	$142,805	$142,546	$142,286	$142,026	$139,702	$139,447	$139,193	$138,938	$138,683	$138,429	$1,690,444
37 - DeSoto Next Generation Solar Energy Center	Solar	$1,084,375	$1,081,210	$1,078,038	$1,074,870	$1,071,670	$1,068,443	$1,051,081	$1,048,130	$1,045,179	$1,042,067	$1,038,956	$1,035,844	$12,719,862
38 - Space Coast Next Generation Solar Energy Center	Solar	$503,179	$501,763	$500,347	$498,848	$497,349	$495,933	$487,890	$486,501	$485,112	$483,724	$482,335	$480,946	$5,903,927
39 - Martin Next Generation Solar Energy Center	Intermediate	$3,008,286	$3,001,131	$2,993,478	$2,986,408	$2,979,480	$2,973,666	$2,925,056	$2,917,768	$2,910,394	$2,903,182	$2,897,972	$2,892,695	$35,389,515
41 - Manatee Temporary Heating System	Distribution	$1,481	$1,481	$1,481	$1,481	$1,481	$1,481	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$17,591
41 - Manatee Temporary Heating System	Intermediate	$7,676	$10,155	$13,367	$15,755	$19,000	$23,883	$31,106	$40,386	$48,177	$53,773	$58,234	$139,796	$461,308
41 - Manatee Temporary Heating System	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$281,260	$292,254	$300,567	$308,388	$343,964	$381,881	$388,984	$405,172	$425,454	$440,488	$448,750	$487,021	$4,504,185
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	$721	$720	$718	$717	$716	$715	$703	$702	$700	$699	$698	$696	$8,504
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$544	$543	$542	$541	$540	$539	$530	$529	$528	$527	$526	$525	$6,415
45 - 800 MW Unit ESP	Intermediate	$785	$783	$780	$772	$764	$761	$751	$749	$3,133	$5,510	$5,492	$5,474	$25,753
45 - 800 MW Unit ESP	Peaking	$2,046,013	$2,040,627	$2,035,240	$2,029,842	$2,024,443	$2,019,057	$1,989,635	$1,984,358	$1,982,447	$1,980,525	$1,975,226	$1,969,928	$24,077,342
54 - Coal Combustion Residuals	Base	$147,562	$143,374	$156,500	$170,188	$182,673	$245,883	$309,215	$330,681	$352,148	$373,614	$395,081	$436,409	$3,243,328
	Total	$12,891,567	$12,872,192	$12,869,115	$12,871,975	$12,902,950	$12,990,747	$12,882,163	$12,905,168	$12,934,244	$12,959,333	$12,972,747	$13,112,688	$155,164,887

[a] 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 2018 THROUGH DECEMBER 2018
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

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	$62,269	94.8545%	$59,065	$59,065	$0
03 - Continuous Emission Monitoring Systems	Base	$29,434	95.7811%	$28,192	$28,192	$0
03 - Continuous Emission Monitoring Systems	Intermediate	$343,416	94.2579%	$323,696	$323,696	$0
03 - Continuous Emission Monitoring Systems	Peaking	$223,443	94.8545%	$211,946	$211,946	$0
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$1,740	95.6652%	$1,665	$128	$1,537
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$613,592	96.9449%	$594,846	$45,757	$549,089
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$249,580	94.1431%	$234,962	$18,074	$216,888
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$808,010	94.7386%	$765,497	$58,884	$706,613
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$1,782	95.6652%	$1,705	$131	$1,574
08 - Oil Spill Clean-up/Response Equipment	Distribution	$268	100.0000%	$268	$21	$248
08 - Oil Spill Clean-up/Response Equipment	General	$558	96.9449%	$541	$42	$499
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$86,430	94.1431%	$81,368	$6,259	$75,109
08 - Oil Spill Clean-up/Response Equipment	Peaking	$64,852	94.7386%	$61,439	$4,726	$56,713
10 - Relocate Storm Water Runoff	Base	$6,513	95.6652%	$6,231	$479	$5,751
12 - Scherer Discharge Pipeline	Base	$35,530	95.6652%	$33,990	$2,615	$31,376
20 - Wastewater Discharge Elimination & Reuse	Peaking	$77,613	94.7386%	$73,530	$5,656	$67,874
21 - St. Lucie Turtle Nets	Base	$740,606	95.6652%	$708,502	$54,500	$654,002
22 - Pipeline Integrity Management	Intermediate	$144,221	94.1431%	$135,774	$10,444	$125,330
22 - Pipeline Integrity Management	Peaking	$125,108	94.7386%	$118,525	$9,117	$109,408
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$339,517	95.6652%	$324,800	$24,985	$299,815
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$251,336	100.0000%	$251,336	$19,334	$232,002
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$10,884	96.9449%	$10,552	$812	$9,740
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$705,323	94.1431%	$664,013	$51,078	$612,935
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$564,342	94.7386%	$534,650	$41,127	$493,523
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$264,052	88.7974%	$234,471	$18,036	$216,435
24 - Manatee Reburn	Intermediate	$3,001	94.2579%	$2,829	$2,829	$0
24 - Manatee Reburn	Peaking	$3,147,124	94.8545%	$2,985,189	$2,985,189	$0
26 - UST Remove/Replacement	General	$6,764	96.9449%	$6,558	$504	$6,053
28 - CWA 316(b) Phase II Rule	Intermediate	$78,782	94.1431%	$74,168	$5,705	$68,463
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$36,477,202	95.6652%	$34,895,988	$2,684,307	$32,211,681
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$106	100.0000%	$106	$8	$98
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$121,179	94.1431%	$114,081	$8,775	$105,306
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$11,557,707	94.7386%	$10,949,610	$842,278	$10,107,332
33 - MATS Project	Base	$9,606,375	95.6652%	$9,189,958	$706,920	$8,483,038
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$347,643	95.6652%	$332,573	$25,583	$306,991
35 - Martin Plant Drinking Water System Compliance	Intermediate	$11,666	94.1431%	$10,983	$845	$10,138
35 - Martin Plant Drinking Water System Compliance	Peaking	$8,801	94.7386%	$8,338	$641	$7,696
36 - Low-Level Radioactive Waste Storage	Base	$1,690,444	95.6652%	$1,617,167	$124,397	$1,492,769
37 - DeSoto Next Generation Solar Energy Center	Solar	$12,719,862	95.6652%	$12,168,481	$936,037	$11,232,444
38 - Space Coast Next Generation Solar Energy Center	Solar	$5,903,927	95.6652%	$5,648,004	$434,462	$5,213,542
39 - Martin Next Generation Solar Energy Center	Intermediate	$35,389,515	94.1431%	$33,316,786	$2,562,830	$30,753,956
41 - Manatee Temporary Heating System	Distribution	$17,591	100.0000%	$17,591	$1,353	$16,238
41 - Manatee Temporary Heating System	Intermediate	$461,308	94.1431%	$434,290	$33,407	$400,883
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$4,504,185	95.6652%	$4,308,937	$331,457	$3,977,481
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$8,504	94.1431%	$8,006	$0	$8,006
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$6,415	94.7386%	$6,078	$0	$6,078
45 - 800 MW Unit ESP	Intermediate	$25,753	94.1431%	$24,245	$0	$24,245
45 - 800 MW Unit ESP	Peaking	$24,077,342	94.7386%	$22,810,537	$0	$22,810,537
54 - Coal Combustion Residuals	Base	$3,243,328	95.6652%	$3,102,736	$238,672	$2,864,064
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($57)	95.7811%	($54)	($54)	$0
	Total	$155,164,887		$147,494,749	$12,921,249	$134,573,499

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

FORM: 42-7E-2

JANUARY 2018 THROUGH DECEMBER 2018
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

	Jan - 2018	Feb - 2018	Mar - 2018	Apr - 2018	May - 2018	Jun - 2018	Jul - 2018	Aug - 2018	Sep - 2018	Oct - 2018	Nov - 2018	Dec - 2018	2018
2. Total of Capital Investment Projects	$12,891,567	$12,872,192	$12,869,115	$12,871,975	$12,902,950	$12,990,747	$12,882,163	$12,905,168	$12,934,244	$12,959,333	$12,972,747	$13,112,688	$155,164,887
3. Recoverable Costs Jurisdictionalized on Energy - Base	$2,503	$2,495	$2,487	$2,480	$2,472	$2,464	$2,431	$2,424	$2,416	$2,409	$2,401	$2,394	$29,377
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$26,861	$26,770	$26,677	$26,572	$26,467	$28,679	$30,750	$30,819	$30,718	$30,617	$30,702	$30,787	$346,417
Recoverable Costs Jurisdictionalized on Energy - Peaking	$291,743	$290,834	$289,929	$289,024	$288,116	$287,550	$284,386	$283,880	$282,987	$282,093	$281,462	$280,832	$3,432,837
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$13,448	$13,542	$14,303	$15,324	$16,808	$19,470	$21,053	$23,686	$26,202	$30,460	$33,820	$35,937	$264,052
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$4,587,858	$4,587,593	$4,602,192	$4,622,853	$4,670,757	$4,768,764	$4,774,866	$4,806,657	$4,841,345	$4,870,785	$4,893,453	$4,967,745	$56,994,866
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$3,136,033	$3,131,057	$3,126,319	$3,121,333	$3,117,344	$3,116,133	$3,072,982	$3,074,680	$3,077,084	$3,078,006	$3,077,608	$3,153,683	$37,282,260
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$3,170,320	$3,161,744	$3,153,167	$3,144,578	$3,135,988	$3,127,411	$3,082,189	$3,073,936	$3,068,818	$3,064,840	$3,057,730	$3,049,468	$37,290,190
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$1,587,554	$1,582,973	$1,578,385	$1,573,717	$1,569,018	$1,564,376	$1,538,972	$1,534,631	$1,530,291	$1,525,791	$1,521,290	$1,516,790	$18,623,789
Recoverable Costs Jurisdictionalized on 12 CP Demand - General	$52,484	$52,434	$52,938	$53,409	$53,328	$53,278	$52,304	$52,255	$52,207	$52,158	$52,109	$52,894	$631,798
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$22,764	$22,749	$22,717	$22,685	$22,653	$22,621	$22,231	$22,199	$22,177	$22,174	$22,172	$22,159	$269,301
5. Retail Production Energy Jurisdictional Factor - Base	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	95.78110%	
Retail Production Energy Jurisdictional Factor - Intermediate	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	94.25790%	
Retail Production Energy Jurisdictional Factor - Peaking	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	94.85450%	
6. Retail Transmission Demand Jurisdictional Factor	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	88.79740%	
Retail Production Demand Jurisdictional Factor - Base	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	
Retail Production Demand Jurisdictional Factor - Intermediate	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	94.14310%	
Retail Production Demand Jurisdictional Factor - Peaking	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	94.73860%	
Retail Production Demand Jurisdictional Factor - Solar	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	95.66520%	
Retail Production Demand Jurisdictional Factor - General	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	96.94490%	
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	$11,941	$12,025	$12,700	$13,607	$14,925	$17,289	$18,695	$21,032	$23,266	$27,048	$30,031	$31,911	$234,471
Jurisdictional Recoverable Costs - Production - Base	$4,391,380	$4,391,120	$4,405,078	$4,424,837	$4,470,657	$4,564,408	$4,570,214	$4,600,620	$4,633,797	$4,661,953	$4,683,631	$4,754,696	$54,552,390
Jurisdictional Recoverable Costs - Production - Inter.	$2,977,677	$2,972,907	$2,968,359	$2,963,565	$2,959,711	$2,960,656	$2,921,984	$2,923,649	$2,925,816	$2,926,589	$2,926,294	$2,997,994	$35,425,201
Jurisdictional Recoverable Costs - Production - Peaking	$3,280,248	$3,271,261	$3,262,278	$3,253,281	$3,244,282	$3,235,620	$3,189,776	$3,181,477	$3,175,781	$3,171,165	$3,163,830	$3,155,405	$38,584,404
Jurisdictional Recoverable Costs - Production - Solar	$1,518,737	$1,514,354	$1,509,965	$1,505,500	$1,501,004	$1,496,564	$1,472,260	$1,468,108	$1,463,956	$1,459,651	$1,455,345	$1,451,040	$17,816,485
Jurisdictional Recoverable Costs - General	$50,881	$50,833	$51,321	$51,777	$51,698	$51,650	$50,706	$50,659	$50,612	$50,565	$50,517	$51,278	$612,496
Jurisdictional Recoverable Costs - Distribution	$22,764	$22,749	$22,717	$22,685	$22,653	$22,621	$22,231	$22,199	$22,177	$22,174	$22,172	$22,159	$269,301
8. Total Jurisdictional Recoverable Costs for Capital Investment Activities	$12,253,628	$12,235,249	$12,232,418	$12,235,253	$12,264,930	$12,348,808	$12,245,865	$12,267,744	$12,295,405	$12,319,144	$12,331,821	$12,464,483	$147,494,749

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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	($338,245)	($335,113)	($331,981)	($328,849)	($325,717)	($322,585)	($319,453)	($316,321)	($313,190)	($310,058)	($306,926)	($303,794)	($300,662)	
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)	$338,245	$335,113	$331,981	$328,849	$325,717	$322,586	$319,454	$316,322	$313,190	$310,058	$306,926	$303,794	$300,662	
6. Average Net Investment		$336,679	$333,547	$330,415	$327,283	$324,152	$321,020	$317,888	$314,756	$311,624	$308,492	$305,360	$302,228	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,813	$1,796	$1,780	$1,763	$1,746	$1,729	$1,673	$1,657	$1,640	$1,624	$1,607	$1,591	$20,420
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$376	$373	$369	$366	$362	$359	$352	$349	$345	$342	$338	$335	$4,267
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)		$5,322	$5,301	$5,281	$5,260	$5,240	$5,220	$5,157	$5,137	$5,118	$5,098	$5,078	$5,058	$62,269

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2018 THROUGH DECEMBER 2018

	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
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		($44,752)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($44,752)
c. Retirements		($44,752)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($44,752)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$560,406	$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	$358,476	$359,674	$360,873	$362,072	$363,271	$364,470	$365,669	$366,868	$368,067	$369,266	$370,465	$371,663	$372,862	
3b. Less: Capital Recovery Unamortized Balance		($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$201,930	$200,731	$199,532	$198,333	$197,135	$195,936	$194,737	$193,538	$192,339	$191,140	$189,941	$188,742	$187,543	
6. Average Net Investment		$201,331	$200,132	$198,933	$197,734	$196,535	$195,336	$194,137	$192,938	$191,739	$190,541	$189,342	$188,143	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,084	$1,078	$1,071	$1,065	$1,059	$1,052	$1,022	$1,016	$1,009	$1,003	$997	$990	$12,446
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$225	$224	$222	$221	$220	$218	$215	$214	$212	$211	$210	$208	$2,601
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)		$2,508	$2,501	$2,493	$2,485	$2,477	$2,469	$2,436	$2,428	$2,421	$2,413	$2,405	$2,398	$29,434

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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
03 - Continuous Emission Monitoring Systems														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$422,864	$34,496	$0	$0	$0	$0	$0	$457,360
b. Clearings to Plant		$188	$0	$0	($2,489)	$0	$422,864	$34,496	$0	$0	$0	$0	$0	$455,058
c. Retirements		$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0	$0	$0	($0)
d. Other (a)		($368)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($368)
2. Plant-In-Service/Depreciation Base (b)	$3,180,705	$3,180,893	$3,180,893	$3,180,893	$3,178,403	$3,178,403	$3,601,267	$3,635,763	$3,635,763	$3,635,763	$3,635,763	$3,635,763	$3,635,763	
3a. Less: Accumulated Depreciation	$1,501,169	$1,512,668	$1,524,535	$1,536,403	$1,548,265	$1,560,124	$1,572,724	$1,586,124	$1,599,586	$1,613,047	$1,626,508	$1,639,970	$1,653,431	
3b. Less: Capital Recovery Unamortized Balance	($261,071)	($258,654)	($256,237)	($253,819)	($251,402)	($248,985)	($246,567)	($244,150)	($241,733)	($239,315)	($236,898)	($234,481)	($232,063)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,940,607	$1,926,879	$1,912,594	$1,898,310	$1,881,540	$1,867,264	$2,275,111	$2,293,789	$2,277,910	$2,262,032	$2,246,153	$2,230,275	$2,214,396	
6. Average Net Investment		$1,933,743	$1,919,736	$1,905,452	$1,889,925	$1,874,402	$2,071,188	$2,284,450	$2,285,850	$2,269,971	$2,254,093	$2,238,214	$2,222,335	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$10,415	$10,340	$10,263	$10,179	$10,095	$11,155	$12,025	$12,032	$11,949	$11,865	$11,782	$11,698	$133,798
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,162	$2,146	$2,130	$2,113	$2,095	$2,315	$2,531	$2,533	$2,515	$2,498	$2,480	$2,463	$27,980
8. Investment Expenses														
a. Depreciation (e)		$11,867	$11,867	$11,867	$11,863	$11,859	$12,600	$13,401	$13,461	$13,461	$13,461	$13,461	$13,461	$152,629
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)		$26,861	$26,770	$26,677	$26,572	$26,467	$28,487	$30,374	$30,444	$30,343	$30,242	$30,140	$30,039	$343,416

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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
03 - Continuous Emission Monitoring Systems														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$60,384	$0	$0	$0	$0	$0	$60,384
b. Clearings to Plant		$0	$0	$0	($0)	$0	$0	$60,384	$0	$0	$0	$0	$0	$60,384
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)	$2,081,676	$2,081,676	$2,081,676	$2,081,676	$2,081,676	$2,081,676	$2,081,676	$2,142,060	$2,142,060	$2,142,060	$2,142,060	$2,142,060	$2,142,060	
3a. Less: Accumulated Depreciation	$911,632	$919,848	$928,063	$936,279	$944,495	$952,711	$960,927	$969,256	$977,700	$986,144	$994,588	$1,003,031	$1,011,475	
3b. Less: Capital Recovery Unamortized Balance	($189,596)	($187,840)	($186,085)	($184,329)	($182,573)	($180,818)	($179,062)	($177,307)	($175,551)	($173,796)	($172,040)	($170,285)	($168,529)	
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)	$1,359,640	$1,349,668	$1,339,697	$1,329,726	$1,319,754	$1,309,783	$1,299,812	$1,350,110	$1,339,911	$1,329,712	$1,319,513	$1,309,313	$1,299,114	
6. Average Net Investment		$1,354,654	$1,344,683	$1,334,711	$1,324,740	$1,314,769	$1,304,797	$1,324,961	$1,345,011	$1,334,811	$1,324,612	$1,314,413	$1,304,214	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$7,296	$7,242	$7,189	$7,135	$7,081	$7,028	$6,974	$7,080	$7,026	$6,973	$6,919	$6,865	$84,808
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,514	$1,503	$1,492	$1,481	$1,470	$1,459	$1,468	$1,490	$1,479	$1,468	$1,457	$1,445	$17,725
8. Investment Expenses														
a. Depreciation (e)		$8,216	$8,216	$8,216	$8,216	$8,216	$8,216	$8,330	$8,444	$8,444	$8,444	$8,444	$8,444	$99,843
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)		$18,782	$18,717	$18,652	$18,587	$18,522	$18,457	$18,528	$18,770	$18,705	$18,640	$18,575	$18,510	$223,443

(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 42-8E, pages 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2018 THROUGH DECEMBER 2018

	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		($44,384)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($44,384)
c. Retirements		($44,384)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($44,384)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$44,384													
3a. Less: Accumulated Depreciation	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	
3b. Less: Capital Recovery Unamortized Balance		($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	
4. 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)		$121	$121	$121	$121	$121	$121	$119	$119	$119	$119	$119	$119	$1,440
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	$301
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)		$147	$147	$147	$147	$147	$147	$144	$144	$144	$144	$144	$144	$1,740

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to charge of $371K for Port Everglades Tanks 903/904, which was incorrectly charged to base rates in August 2017 and is now being correctly included in ECRC.

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

JANUARY 2018 THROUGH DECEMBER 2018

	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														
General														
1. Investments														
a. Expenditures/Additions		$0	$113	$170,081	$0	$0	$0	$0	$0	$0	$0	$0	$0	$170,194
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,336,763	$1,336,763
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	$7,174,603	
3a. Less: Accumulated Depreciation	$297,000	$304,297	$311,595	$318,892	$326,189	$333,487	$340,784	$348,081	$355,379	$362,676	$369,973	$377,270	$385,403	
4. CWIP Non-Interest Bearing	$1,166,569	$1,166,569	$1,166,682	$1,336,763	$1,336,763	$1,336,763	$1,336,763	$1,336,763	$1,336,763	$1,336,763	$1,336,763	$1,336,763	$0	
5. Net Investment (Lines 2 - 3 + 4)	$6,707,409	$6,700,112	$6,692,927	$6,855,711	$6,848,414	$6,841,116	$6,833,819	$6,826,522	$6,819,225	$6,811,927	$6,804,630	$6,797,333	$6,789,200	
6. Average Net Investment		$6,703,760	$6,696,519	$6,774,319	$6,852,062	$6,844,765	$6,837,468	$6,830,170	$6,822,873	$6,815,576	$6,808,279	$6,800,981	$6,793,266	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$36,106	$36,067	$36,486	$36,905	$36,866	$36,826	$35,953	$35,914	$35,876	$35,838	$35,799	$35,758	$434,395
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$7,493	$7,485	$7,572	$7,659	$7,651	$7,643	$7,569	$7,560	$7,552	$7,544	$7,536	$7,528	$90,794
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	$8,133	$88,403
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)		$50,897	$50,850	$51,356	$51,862	$51,814	$51,767	$50,819	$50,772	$50,726	$50,679	$50,633	$51,419	$613,592

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to charge of $371K for Port Everglades Tanks 903/904, which was incorrectly charged to base rates in August 2017 and is now being correctly included in ECRC.

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

JANUARY 2018 THROUGH DECEMBER 2018

	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														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	($344)	$0	$0	$0	$0	$0	$0	$0	$0	($344)
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($68)	($68)
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)	$2,708,135	$2,708,135	$2,708,135	$2,708,135	$2,708,135	$2,708,135	$2,708,135	$2,708,135	$2,708,135	$2,708,135	$2,708,135	$2,708,135	$2,708,067	
3a. Less: Accumulated Depreciation	$1,310,739	$1,317,613	$1,324,488	$1,331,363	$1,338,238	$1,345,113	$1,351,988	$1,358,863	$1,365,738	$1,372,612	$1,379,487	$1,386,362	$1,393,237	
3b. Less: Capital Recovery Unamortized Balance	($334,906)	($331,750)	($328,593)	($325,437)	($322,281)	($319,124)	($315,968)	($312,811)	($309,655)	($306,498)	($303,342)	($300,185)	($297,029)	
4. CWIP Non-Interest Bearing	$276	$276	$276	$276	($68)	($68)	($68)	($68)	($68)	($68)	($68)	($68)	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,732,579	$1,722,548	$1,712,516	$1,702,485	$1,692,109	$1,682,078	$1,672,047	$1,662,015	$1,651,984	$1,641,953	$1,631,922	$1,621,890	$1,611,859	
6. Average Net Investment		$1,727,563	$1,717,532	$1,707,501	$1,697,297	$1,687,094	$1,677,062	$1,667,031	$1,657,000	$1,646,969	$1,636,937	$1,626,906	$1,616,875	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$9,305	$9,251	$9,197	$9,142	$9,087	$9,033	$8,775	$8,722	$8,669	$8,617	$8,564	$8,511	$106,870
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,931	$1,920	$1,909	$1,897	$1,886	$1,875	$1,847	$1,836	$1,825	$1,814	$1,803	$1,792	$22,334
8. Investment Expenses														
a. Depreciation (e)		$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$82,498
b. Amortization (f)		$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$37,877
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)		$21,267	$21,202	$21,137	$21,070	$21,004	$20,939	$20,653	$20,590	$20,526	$20,462	$20,398	$20,334	$249,580

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to charge of $371K for Port Everglades Tanks 903/904, which was incorrectly charged to base rates in August 2017 and is now being correctly included in ECRC.

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
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	($260)	$0	$0	$0	$0	$0	$0	$0	$0	($260)
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($52)	($52)
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$64	$0	$0	$0	$0	$0	$0	$0	$0	$64
2. Plant-In-Service/Depreciation Base (b)	$4,936,977	$4,936,977	$4,936,977	$4,936,977	$4,936,977	$4,936,977	$4,936,977	$4,936,977	$4,936,977	$4,936,977	$4,936,977	$4,936,977	$4,936,925	
3a. Less: Accumulated Depreciation	$2,577,753	$2,592,058	$2,606,363	$2,620,667	$2,635,036	$2,649,341	$2,663,645	$2,677,950	$2,692,255	$2,706,559	$2,720,864	$2,735,169	$2,749,473	
3b. Less: Capital Recovery Unamortized Balance	($2,505,994)	($2,482,847)	($2,459,700)	($2,436,552)	($2,413,405)	($2,390,258)	($2,367,110)	($2,343,963)	($2,320,815)	($2,297,668)	($2,274,521)	($2,251,373)	($2,228,226)	
4. CWIP Non-Interest Bearing	$208	$208	$208	$208	($52)	($52)	($52)	($52)	($52)	($52)	($52)	($52)	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,865,426	$4,827,974	$4,790,522	$4,753,070	$4,715,294	$4,677,842	$4,640,390	$4,602,938	$4,565,486	$4,528,034	$4,490,582	$4,453,130	$4,415,678	
6. Average Net Investment		$4,846,700	$4,809,248	$4,771,796	$4,734,182	$4,696,568	$4,659,116	$4,621,664	$4,584,212	$4,546,760	$4,509,308	$4,471,856	$4,434,404	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$26,104	$25,902	$25,701	$25,498	$25,296	$25,094	$24,328	$24,130	$23,933	$23,736	$23,539	$23,342	$296,604
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$5,418	$5,376	$5,334	$5,292	$5,250	$5,208	$5,121	$5,080	$5,038	$4,997	$4,955	$4,914	$61,982
8. Investment Expenses														
a. Depreciation (e)		$14,305	$14,305	$14,305	$14,305	$14,305	$14,305	$14,305	$14,305	$14,305	$14,305	$14,305	$14,305	$171,656
b. Amortization (f)		$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$277,768
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)		$68,974	$68,730	$68,487	$68,242	$67,997	$67,754	$66,901	$66,662	$66,424	$66,185	$65,946	$65,708	$808,010

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to charge of $371K for Port Everglades Tanks 903/904, which was incorrectly charged to base rates in August 2017 and is now being correctly included in ECRC.

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
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	$27,697	$27,830	$27,962	$28,094	$28,226	$28,358	$28,490	$28,622	$28,755	$28,887	$29,019	$29,151	$29,283	
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)	$3,333	$3,200	$3,068	$2,936	$2,804	$2,672	$2,540	$2,408	$2,275	$2,143	$2,011	$1,879	$1,747	
6. Average Net Investment		$3,267	$3,134	$3,002	$2,870	$2,738	$2,606	$2,474	$2,342	$2,209	$2,077	$1,945	$1,813	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$18	$17	$16	$15	$15	$14	$13	$12	$12	$11	$10	$10	$163
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$4	$4	$3	$3	$3	$3	$3	$3	$2	$2	$2	$2	$34
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)		$153	$153	$152	$151	$150	$149	$148	$147	$146	$145	$145	$144	$1,782

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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	$269	$274	$279	$284	$289	$294	$299	$304	$309	$314	$319	$324	$329	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,726	$2,721	$2,716	$2,711	$2,706	$2,701	$2,696	$2,691	$2,686	$2,681	$2,676	$2,672	$2,667	
6. Average Net Investment		$2,724	$2,719	$2,714	$2,709	$2,704	$2,699	$2,694	$2,689	$2,684	$2,679	$2,674	$2,669	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$15	$15	$15	$15	$15	$15	$14	$14	$14	$14	$14	$14	$172
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	$36
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)		$23	$23	$23	$23	$23	$23	$22	$22	$22	$22	$22	$22	$268

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

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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	($2,291)	$0	$0	$0	$0	$0	$0	$0	$0	($2,291)
c. Retirements		$0	$0	$0	($2,291)	$0	$0	$0	$0	$0	$0	$0	$0	($2,291)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$6,704	$6,704	$6,704	$6,704	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	$4,413	
3a. Less: Accumulated Depreciation	$3,005	$3,075	$3,144	$3,213	$959	$964	$970	$976	$981	$987	$992	$998	$1,003	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,699	$3,629	$3,560	$3,491	$3,454	$3,448	$3,443	$3,437	$3,432	$3,426	$3,421	$3,415	$3,410	
6. Average Net Investment		$3,664	$3,595	$3,526	$3,472	$3,451	$3,446	$3,440	$3,434	$3,429	$3,423	$3,418	$3,412	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$20	$19	$19	$19	$19	$19	$18	$18	$18	$18	$18	$18	$222
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	$46
8. Investment Expenses														
a. Depreciation (e)		$69	$69	$69	$37	$6	$6	$6	$6	$6	$6	$6	$6	$289
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)		$93	$93	$92	$60	$28	$28	$27	$27	$27	$27	$27	$27	$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 42-8E, pages 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

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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		$0	$0	$0	$0	$0	$0	$0	$0	$0	$37,047	$0	$0	$37,047
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$13	$0	($18,044)	$37,047	($5,286)	$0	$13,731
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	($18,044)	$0	($5,286)	$0	($23,330)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$477,647	$477,647	$477,647	$477,647	$477,647	$477,647	$477,647	$477,661	$477,661	$459,616	$496,664	$491,378	$491,378	
3a. Less: Accumulated Depreciation	($37,003)	($33,066)	($29,130)	($25,193)	($21,257)	($17,321)	($13,384)	($9,448)	($5,511)	($19,726)	($15,696)	($16,674)	($12,398)	
3b. Less: Capital Recovery Unamortized Balance	$198	$196	$194	$192	$190	$189	$187	$185	$183	$181	$179	$178	$176	
4. CWIP Non-Interest Bearing	$17	$17	$17	$17	$17	$17	$17	$4	$4	$4	$4	$4	$4	
5. Net Investment (Lines 2 - 3 + 4)	$514,470	$510,535	$506,600	$502,666	$498,731	$494,796	$490,862	$486,927	$482,992	$479,165	$512,184	$507,878	$503,603	
6. Average Net Investment		$512,502	$508,568	$504,633	$500,698	$496,764	$492,829	$488,894	$484,960	$481,079	$495,674	$510,031	$505,741	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$2,760	$2,739	$2,718	$2,697	$2,676	$2,654	$2,573	$2,553	$2,532	$2,609	$2,685	$2,662	$31,859
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$573	$568	$564	$560	$555	$551	$542	$537	$533	$549	$565	$560	$6,658
8. Investment Expenses														
a. Depreciation (e)		$3,936	$3,936	$3,936	$3,936	$3,936	$3,937	$3,937	$3,937	$3,829	$4,030	$4,308	$4,276	$47,935
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)		$7,268	$7,242	$7,217	$7,191	$7,165	$7,140	$7,050	$7,025	$6,893	$7,187	$7,556	$7,497	$86,430

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

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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	$0	$27,948	$0	$0	$27,948
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$17	$0	($13,612)	$27,948	($3,987)	$0	$10,365
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	($13,612)	$0	($3,987)	$0	($17,600)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$449,897	$449,897	$449,897	$449,897	$449,897	$449,897	$449,897	$449,915	$449,915	$436,302	$464,250	$460,263	$460,263	
3a. Less: Accumulated Depreciation	$99,188	$102,389	$105,589	$108,790	$111,991	$115,191	$118,392	$121,444	$124,644	$114,152	$117,423	$116,916	$120,373	
4. CWIP Non-Interest Bearing	$13	$13	$13	$13	$13	$13	$13	($4)	($4)	($4)	($4)	($4)	($4)	
5. Net Investment (Lines 2 - 3 + 4)	$350,723	$347,522	$344,322	$341,121	$337,920	$334,720	$331,519	$328,467	$325,266	$322,147	$346,823	$343,343	$339,886	
6. Average Net Investment		$349,123	$345,922	$342,721	$339,521	$336,320	$333,119	$329,993	$326,867	$323,707	$334,485	$345,083	$341,614	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,880	$1,863	$1,846	$1,829	$1,811	$1,794	$1,737	$1,721	$1,704	$1,761	$1,816	$1,798	$21,560
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$390	$387	$383	$380	$376	$372	$366	$362	$359	$371	$382	$379	$4,506
8. Investment Expenses														
a. Depreciation (e)		$3,201	$3,201	$3,201	$3,201	$3,201	$3,201	$3,052	$3,201	$3,120	$3,272	$3,481	$3,457	$38,785
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)		$5,471	$5,450	$5,430	$5,409	$5,388	$5,367	$5,155	$5,283	$5,182	$5,403	$5,679	$5,634	$64,852

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

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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	$66,478	$66,698	$66,919	$67,140	$67,361	$67,582	$67,803	$68,024	$68,244	$68,465	$68,686	$68,907	$69,128	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$51,316	$51,095	$50,875	$50,654	$50,433	$50,212	$49,991	$49,770	$49,549	$49,328	$49,108	$48,887	$48,666	
6. Average Net Investment	$24,443	$51,206	$50,985	$50,764	$50,543	$50,322	$50,101	$49,881	$49,660	$49,439	$49,218	$48,997	$48,776	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$276	$275	$273	$272	$271	$270	$263	$261	$260	$259	$258	$257	$3,195
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$57	$57	$57	$56	$56	$56	$55	$55	$55	$55	$54	$54	$668
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)		$554	$552	$551	$550	$548	$547	$539	$537	$536	$534	$533	$532	$6,513

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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	$584,487	$585,759	$587,032	$588,305	$589,577	$590,850	$592,122	$593,395	$594,668	$595,940	$597,213	$598,485	$599,758	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$269,837	$268,564	$267,292	$266,019	$264,746	$263,474	$262,201	$260,929	$259,656	$258,383	$257,111	$255,838	$254,566	
6. Average Net Investment		$269,201	$267,928	$266,655	$265,383	$264,110	$262,838	$261,565	$260,292	$259,020	$257,747	$256,475	$255,202	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,450	$1,443	$1,436	$1,429	$1,422	$1,416	$1,377	$1,370	$1,363	$1,357	$1,350	$1,343	$16,757
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$301	$299	$298	$297	$295	$294	$290	$288	$287	$286	$284	$283	$3,502
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)		$3,023	$3,015	$3,007	$2,999	$2,990	$2,982	$2,939	$2,931	$2,923	$2,915	$2,907	$2,899	$35,530

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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)	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	
3a. Less: Accumulated Depreciation	$207,503	$210,452	$213,402	$216,352	$219,301	$222,251	$225,201	$228,151	$231,100	$234,050	$237,000	$239,949	$242,899	
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)	$564,074	$561,124	$558,175	$555,225	$552,275	$549,326	$546,376	$543,426	$540,476	$537,527	$534,577	$531,627	$528,678	
6. Average Net Investment		$562,599	$559,650	$556,700	$553,750	$550,800	$547,851	$544,901	$541,951	$539,002	$536,052	$533,102	$530,152	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$3,030	$3,014	$2,998	$2,982	$2,967	$2,951	$2,868	$2,853	$2,837	$2,822	$2,806	$2,791	$34,919
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$629	$626	$622	$619	$616	$612	$604	$601	$597	$594	$591	$587	$7,298
8. Investment Expenses														
a. Depreciation (e)		$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$35,397
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)		$6,609	$6,590	$6,570	$6,551	$6,532	$6,513	$6,422	$6,403	$6,384	$6,365	$6,347	$6,328	$77,613

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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
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	($742,007)	($729,051)	($716,096)	($703,140)	($690,185)	($677,229)	($664,274)	($651,319)	($638,363)	($625,408)	($612,452)	($599,497)	($586,541)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$7,651,565	$7,638,610	$7,625,654	$7,612,699	$7,599,743	$7,586,788	$7,573,833	$7,560,877	$7,547,922	$7,534,966	$7,522,011	$7,509,055	$7,496,100	
6. Average Net Investment		$7,645,087	$7,632,132	$7,619,177	$7,606,221	$7,593,266	$7,580,310	$7,567,355	$7,554,399	$7,541,444	$7,528,489	$7,515,533	$7,502,578	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$41,176	$41,106	$41,037	$40,967	$40,897	$40,827	$39,833	$39,765	$39,697	$39,629	$39,560	$39,492	$483,987
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$8,546	$8,531	$8,517	$8,502	$8,488	$8,473	$8,385	$8,371	$8,357	$8,342	$8,328	$8,314	$101,154
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)		$62,677	$62,593	$62,509	$62,425	$62,340	$62,256	$61,174	$61,091	$61,009	$60,926	$60,844	$60,761	$740,606

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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	$181,985	$185,363	$188,741	$192,119	$195,497	$198,875	$202,253	$205,632	$209,010	$212,388	$215,766	$219,144	$222,522	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,362,277	$1,358,898	$1,355,520	$1,352,142	$1,348,764	$1,345,386	$1,342,008	$1,338,630	$1,335,252	$1,331,874	$1,328,496	$1,325,118	$1,321,740	
6. Average Net Investment		$1,360,587	$1,357,209	$1,353,831	$1,350,453	$1,347,075	$1,343,697	$1,340,319	$1,336,941	$1,333,563	$1,330,185	$1,326,807	$1,323,429	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$7,328	$7,310	$7,292	$7,274	$7,255	$7,237	$7,055	$7,037	$7,020	$7,002	$6,984	$6,966	$85,760
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,521	$1,517	$1,513	$1,510	$1,506	$1,502	$1,485	$1,481	$1,478	$1,474	$1,470	$1,466	$17,924
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)		$12,227	$12,205	$12,183	$12,161	$12,139	$12,117	$11,918	$11,897	$11,875	$11,854	$11,832	$11,811	$144,221

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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	$154,266	$157,246	$160,226	$163,207	$166,187	$169,168	$172,148	$175,129	$178,109	$181,090	$184,070	$187,050	$190,031	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,174,264	$1,171,284	$1,168,303	$1,165,323	$1,162,342	$1,159,362	$1,156,381	$1,153,401	$1,150,421	$1,147,440	$1,144,460	$1,141,479	$1,138,499	
6. Average Net Investment		$1,172,774	$1,169,793	$1,166,813	$1,163,833	$1,160,852	$1,157,872	$1,154,891	$1,151,911	$1,148,930	$1,145,950	$1,142,970	$1,139,989	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,317	$6,300	$6,284	$6,268	$6,252	$6,236	$6,079	$6,063	$6,048	$6,032	$6,016	$6,001	$73,898
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,311	$1,308	$1,304	$1,301	$1,298	$1,294	$1,280	$1,276	$1,273	$1,270	$1,267	$1,263	$15,444
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)		$10,608	$10,589	$10,569	$10,550	$10,530	$10,511	$10,339	$10,320	$10,301	$10,282	$10,263	$10,244	$125,108

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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														
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	$242,556	$12,029	$0	$0	$0	$0	$0	$0	$0	$254,584
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)	$2,987,885	$2,987,885	$2,987,885	$2,987,885	$3,230,440	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	
3a. Less: Accumulated Depreciation	$481,051	$490,399	$499,747	$509,096	$519,882	$532,135	$544,415	$556,696	$568,976	$581,256	$593,537	$605,817	$618,097	
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)	$2,506,833	$2,497,485	$2,488,137	$2,478,789	$2,710,558	$2,710,334	$2,698,054	$2,685,773	$2,673,493	$2,661,213	$2,648,932	$2,636,652	$2,624,371	
6. Average Net Investment		$2,502,159	$2,492,811	$2,483,463	$2,594,674	$2,710,446	$2,704,194	$2,691,913	$2,679,633	$2,667,353	$2,655,072	$2,642,792	$2,630,512	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$13,477	$13,426	$13,376	$13,975	$14,598	$14,565	$14,170	$14,105	$14,040	$13,976	$13,911	$13,847	$167,465
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,797	$2,786	$2,776	$2,900	$3,030	$3,023	$2,983	$2,969	$2,956	$2,942	$2,928	$2,915	$35,006
8. Investment Expenses														
a. Depreciation (e)		$9,348	$9,348	$9,348	$10,787	$12,253	$12,280	$12,280	$12,280	$12,280	$12,280	$12,280	$12,280	$137,046
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)		$25,622	$25,561	$25,500	$27,662	$29,881	$29,868	$29,433	$29,355	$29,276	$29,198	$29,120	$29,042	$339,517

(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 42-8E, pages 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

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

JANUARY 2018 THROUGH DECEMBER 2018

	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	$0	$0	$0	$0	$3,000	$6,000	$3,000	$3,000	$15,000
b. Clearings to Plant		$5,249	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,249
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$45	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$45
2. Plant-In-Service/Depreciation Base (b)	$3,368,668	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	
3a. Less: Accumulated Depreciation	$862,109	$867,089	$872,024	$876,959	$881,894	$886,829	$891,764	$896,699	$901,634	$906,569	$911,504	$916,439	$921,374	
4. CWIP Non-Interest Bearing	$2,125	$2,125	$2,125	$2,125	$2,125	$2,125	$2,125	$2,125	$2,125	$5,125	$11,125	$14,125	$17,125	
5. Net Investment (Lines 2 - 3 + 4)	$2,508,684	$2,508,953	$2,504,018	$2,499,083	$2,494,148	$2,489,213	$2,484,278	$2,479,343	$2,474,408	$2,472,473	$2,473,538	$2,471,603	$2,469,668	
6. Average Net Investment	$1,231,956	$2,508,818	$2,506,485	$2,501,550	$2,496,615	$2,491,680	$2,486,745	$2,481,810	$2,476,876	$2,473,441	$2,473,006	$2,472,571	$2,470,636	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$13,512	$13,500	$13,473	$13,447	$13,420	$13,394	$13,064	$13,038	$13,020	$13,017	$13,015	$13,005	$158,905
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,804	$2,802	$2,796	$2,791	$2,785	$2,780	$2,750	$2,745	$2,741	$2,740	$2,740	$2,738	$33,211
8. Investment Expenses														
a. Depreciation (e)		$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$59,220
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)		$21,252	$21,237	$21,204	$21,172	$21,140	$21,108	$20,749	$20,717	$20,696	$20,693	$20,690	$20,678	$251,336

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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	$33,192	$33,376	$33,559	$33,742	$33,926	$34,109	$34,292	$34,476	$34,659	$34,842	$35,026	$35,209	$35,393	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$113,499	$113,316	$113,132	$112,949	$112,766	$112,582	$112,399	$112,216	$112,032	$111,849	$111,666	$111,482	$111,299	
6. Average Net Investment		$113,407	$113,224	$113,041	$112,857	$112,674	$112,491	$112,307	$112,124	$111,941	$111,757	$111,574	$111,390	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$611	$610	$609	$608	$607	$606	$591	$590	$589	$588	$587	$586	$7,183
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$127	$127	$126	$126	$126	$126	$124	$124	$124	$124	$124	$123	$1,501
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)		$921	$920	$919	$917	$916	$915	$899	$898	$897	$895	$894	$893	$10,884

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

FLORIDA POWER & LIGHT COMPANY
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JANUARY 2018 THROUGH DECEMBER 2018

	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	$0	$0	$0	$0	$0	$0	$0	$0	$41,759	$41,759	$0	$83,518
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$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)	$5,309,419	$5,309,419	$5,309,419	$5,309,419	$5,309,419	$5,309,419	$5,309,419	$5,309,419	$5,309,419	$5,309,419	$5,309,419	$5,309,419	$5,309,419	
3a. Less: Accumulated Depreciation	$806,184	$818,505	$830,825	$843,146	$855,466	$867,786	$880,126	$892,466	$904,806	$917,145	$929,485	$941,825	$954,165	
3b. Less: Capital Recovery Unamortized Balance	($1,146,350)	($1,135,473)	($1,124,596)	($1,113,719)	($1,102,842)	($1,091,965)	($1,081,088)	($1,070,211)	($1,059,334)	($1,048,457)	($1,037,579)	($1,026,702)	($1,015,825)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$41,759	$83,518	$83,518	
5. Net Investment (Lines 2 - 3 + 4)	$5,649,585	$5,626,388	$5,603,190	$5,579,993	$5,556,795	$5,533,598	$5,510,381	$5,487,164	$5,463,947	$5,440,730	$5,459,272	$5,477,814	$5,454,597	
6. Average Net Investment		$5,637,987	$5,614,789	$5,591,592	$5,568,394	$5,545,197	$5,521,989	$5,498,773	$5,475,556	$5,452,339	$5,450,001	$5,468,543	$5,466,206	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$30,366	$30,241	$30,116	$29,991	$29,866	$29,741	$28,945	$28,822	$28,700	$28,688	$28,785	$28,773	$353,035
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$6,302	$6,276	$6,250	$6,224	$6,198	$6,172	$6,093	$6,067	$6,042	$6,039	$6,060	$6,057	$73,782
8. Investment Expenses														
a. Depreciation (e)		$12,320	$12,320	$12,320	$12,320	$12,320	$12,340	$12,340	$12,340	$12,340	$12,340	$12,340	$12,340	$147,980
b. Amortization (f)		$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$130,525
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)		$59,866	$59,715	$59,564	$59,413	$59,262	$59,131	$58,255	$58,107	$57,959	$57,944	$58,062	$58,047	$705,323

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

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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		$0	$0	$0	$0	$0	$0	$0	$0	$0	$260,161	$58,881	$0	$319,042
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$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)	$3,324,788	$3,324,788	$3,324,788	$3,324,788	$3,324,788	$3,324,788	$3,324,788	$3,324,788	$3,324,788	$3,324,788	$3,324,788	$3,324,788	$3,324,788	
3a. Less: Accumulated Depreciation	$1,261,428	$1,273,922	$1,286,416	$1,298,910	$1,311,404	$1,323,898	$1,336,392	$1,348,887	$1,361,381	$1,373,875	$1,386,369	$1,398,863	$1,411,357	
3b. Less: Capital Recovery Unamortized Balance	($1,407,405)	($1,394,636)	($1,381,867)	($1,369,098)	($1,356,329)	($1,343,561)	($1,330,792)	($1,318,023)	($1,305,254)	($1,292,486)	($1,279,717)	($1,266,948)	($1,254,179)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$260,161	$319,042	$319,042	
5. Net Investment (Lines 2 - 3 + 4)	$3,470,765	$3,445,502	$3,420,239	$3,394,976	$3,369,714	$3,344,451	$3,319,188	$3,293,925	$3,268,662	$3,243,399	$3,478,298	$3,511,916	$3,486,653	
6. Average Net Investment		$3,458,134	$3,432,871	$3,407,608	$3,382,345	$3,357,082	$3,331,819	$3,306,557	$3,281,294	$3,256,031	$3,360,849	$3,495,107	$3,499,285	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$18,625	$18,489	$18,353	$18,217	$18,081	$17,945	$17,405	$17,272	$17,139	$17,691	$18,398	$18,420	$216,036
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3,866	$3,837	$3,809	$3,781	$3,753	$3,724	$3,664	$3,636	$3,608	$3,724	$3,873	$3,878	$45,152
8. Investment Expenses														
a. Depreciation (e)		$12,494	$12,494	$12,494	$12,494	$12,494	$12,494	$12,494	$12,494	$12,494	$12,494	$12,494	$12,494	$149,929
b. Amortization (f)		$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$153,225
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)		$47,754	$47,589	$47,425	$47,261	$47,097	$46,932	$46,332	$46,171	$46,010	$46,678	$47,533	$47,560	$564,342

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

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23 - SPCC - Spill Prevention, Control & Countermeasures														
Transmission														
1. Investments														
a. Expenditures/Additions		$22,643	$10,499	$227,393	$90,726	$369,661	$453,172	$253,331	$481,810	$311,955	$205,583	$29,941	$498,398	$2,955,113
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,094,935	$19,941	$558,398	$3,673,274
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	$1,393,224	$1,393,224	$1,393,224	$1,393,224	$4,488,159	$4,508,100	$5,066,498	
3a. Less: Accumulated Depreciation	$366,681	$368,714	$370,748	$372,781	$374,815	$376,848	$378,882	$380,613	$382,646	$384,680	$389,344	$396,656	$404,450	
4. CWIP Non-Interest Bearing	$718,161	$740,805	$751,303	$978,697	$1,069,423	$1,439,084	$1,892,256	$2,145,587	$2,627,397	$2,939,352	$50,000	$60,000	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,744,704	$1,765,314	$1,773,779	$1,999,139	$2,087,832	$2,455,459	$2,906,598	$3,158,198	$3,637,975	$3,947,896	$4,148,815	$4,171,444	$4,662,048	
6. Average Net Investment		$1,755,009	$1,769,546	$1,886,459	$2,043,485	$2,271,646	$2,681,029	$3,032,398	$3,398,086	$3,792,935	$4,048,356	$4,160,130	$4,416,746	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$9,452	$9,531	$10,160	$11,006	$12,235	$14,440	$15,962	$17,887	$19,965	$21,310	$21,898	$23,249	$187,096
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,962	$1,978	$2,109	$2,284	$2,539	$2,997	$3,360	$3,765	$4,203	$4,486	$4,610	$4,894	$39,187
8. Investment Expenses														
a. Depreciation (e)		$2,033	$2,033	$2,033	$2,033	$2,033	$2,033	$1,731	$2,033	$2,033	$4,664	$7,312	$7,794	$37,769
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)		$13,448	$13,542	$14,303	$15,324	$16,808	$19,470	$21,053	$23,686	$26,202	$30,460	$33,820	$35,937	$264,052

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

Note: Change in beginning balance is due to incorrect charge of $178K moved from Project 8 - Oil Spill Clean-Up/Response Equipment to Project 23 - Spill Prevention, Control & Countermeasures.

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
24 - Manatee Reburn														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$58,883	$0	$0	$0	$0	$58,462	$0	$117,346
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$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		$0	$0	$0	$0	$0	$58,883	$58,883	$58,883	$58,883	$58,883	$117,346	$117,346	
5. Net Investment (Lines 2 - 3 + 4)							$58,883	$58,883	$58,883	$58,883	$58,883	$117,346	$117,346	
6. Average Net Investment							$29,442	$58,883	$58,883	$58,883	$58,883	$88,115	$117,346	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$0	$0	$0	$0	$159	$310	$310	$310	$310	$464	$618	$2,480
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$0	$0	$0	$0	$0	$33	$65	$65	$65	$65	$98	$130	$522
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	$191	$375	$375	$375	$375	$561	$748	$3,001

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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	$1,032	$0	$0	$83,028	$0	$0	$0	$0	$82,434	$0	$166,493
b. Clearings to Plant		$0	$0	$0	$0	$0	$37,701	$38,570	$0	$0	$0	$0	$0	$76,271
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)	$31,581,736	$31,581,736	$31,581,736	$31,581,736	$31,581,736	$31,581,736	$31,619,436	$31,658,006	$31,658,006	$31,658,006	$31,658,006	$31,658,006	$31,658,006	
3a. Less: Accumulated Depreciation	$9,903,555	$10,030,126	$10,156,698	$10,283,270	$10,409,842	$10,536,414	$10,663,059	$10,789,856	$10,916,734	$11,043,612	$11,170,490	$11,297,368	$11,424,246	
4. CWIP Non-Interest Bearing	$75,239	$75,239	$75,239	$76,270	$76,270	$76,270	$121,597	$83,028	$83,028	$83,028	$83,028	$165,461	$165,461	
5. Net Investment (Lines 2 - 3 + 4)	$21,753,420	$21,626,848	$21,500,276	$21,374,736	$21,248,164	$21,121,592	$21,077,975	$20,951,177	$20,824,299	$20,697,421	$20,570,543	$20,526,099	$20,399,221	
6. Average Net Investment		$21,690,134	$21,563,562	$21,437,506	$21,311,450	$21,184,878	$21,099,784	$21,014,576	$20,887,738	$20,760,860	$20,633,982	$20,548,321	$20,462,660	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$116,823	$116,141	$115,462	$114,783	$114,101	$113,643	$110,617	$109,949	$109,281	$108,613	$108,163	$107,712	$1,345,287
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$24,245	$24,104	$23,963	$23,822	$23,680	$23,585	$23,286	$23,146	$23,005	$22,865	$22,770	$22,675	$281,145
8. Investment Expenses														
a. Depreciation (e)		$126,572	$126,572	$126,572	$126,572	$126,572	$126,645	$126,798	$126,878	$126,878	$126,878	$126,878	$126,878	$1,520,692
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)		$267,640	$266,816	$265,997	$265,177	$264,354	$263,873	$260,701	$259,973	$259,164	$258,356	$257,810	$257,264	$3,147,124

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
26 - UST Remove/Replacement														
General														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	
3a. Less: Accumulated Depreciation	$49,440	$49,584	$49,728	$49,872	$50,017	$50,161	$50,305	$50,450	$50,594	$50,738	$50,883	$51,027	$51,171	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$66,007	$65,863	$65,719	$65,574	$65,430	$65,286	$65,141	$64,997	$64,853	$64,708	$64,564	$64,420	$64,275	
6. Average Net Investment		$65,935	$65,791	$65,646	$65,502	$65,358	$65,213	$65,069	$64,925	$64,781	$64,636	$64,492	$64,348	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$355	$354	$354	$353	$352	$351	$343	$342	$341	$340	$339	$339	$4,163
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$74	$74	$73	$73	$73	$73	$72	$72	$72	$72	$71	$71	$870
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)		$573	$572	$571	$570	$569	$568	$559	$558	$557	$556	$555	$554	$6,764

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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
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		$13	$0	$483	$13	$0	$0	$0	$0	$0	$0	$0	$0	$508
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)	$766,645	$766,657	$766,657	$767,140	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	
3a. Less: Accumulated Depreciation	$4,092	$5,810	$7,529	$9,248	$10,968	$12,687	$14,407	$16,127	$17,846	$19,566	$21,286	$23,005	$24,725	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$762,553	$760,847	$759,129	$757,892	$756,185	$754,465	$752,745	$751,026	$749,306	$747,586	$745,867	$744,147	$742,427	
6. Average Net Investment		$761,700	$759,988	$758,510	$757,038	$755,325	$753,605	$751,886	$750,166	$748,446	$746,727	$745,007	$743,287	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$4,102	$4,093	$4,085	$4,077	$4,068	$4,059	$3,958	$3,949	$3,940	$3,931	$3,922	$3,913	$48,096
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$851	$850	$848	$846	$844	$842	$833	$831	$829	$827	$826	$824	$10,052
8. Investment Expenses														
a. Depreciation (e)		$1,719	$1,719	$1,719	$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$20,634
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)		$6,673	$6,661	$6,652	$6,643	$6,632	$6,621	$6,511	$6,500	$6,489	$6,478	$6,467	$6,456	$78,782

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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JANUARY 2018 THROUGH DECEMBER 2018

	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	$13,449	$10,870	$156,419	$129,109	$727,660	$203,512	$0	$0	$0	$0	$0	$1,241,019
b. Clearings to Plant		($55,155,627)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$309,847	($54,845,780)
c. Retirements		($55,172,833)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($55,172,833)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$412,029,045	$356,873,418	$356,873,418	$356,873,418	$356,873,418	$356,873,418	$356,873,418	$356,873,418	$356,873,418	$356,873,418	$356,873,418	$356,873,418	$357,183,265	
3a. Less: Accumulated Depreciation	$58,723,930	$59,514,959	$60,306,005	$61,097,051	$61,888,097	$62,679,142	$63,470,188	$64,261,234	$65,052,279	$65,843,325	$66,634,371	$67,425,417	$68,216,762	
3b. Less: Capital Recovery Unamortized Balance	$0	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	
4. CWIP Non-Interest Bearing	$0	$0	$13,449	$24,319	$180,738	$309,847	$1,037,507	$1,241,019	$1,241,019	$1,241,019	$1,241,019	$1,241,019	$931,172	
5. Net Investment (Lines 2 - 3 + 4)	$353,305,115	$352,531,292	$351,753,695	$350,973,519	$350,338,893	$349,676,956	$349,613,570	$349,026,036	$348,234,990	$347,443,945	$346,652,899	$345,861,853	$345,070,508	
6. Average Net Investment		$352,918,203	$352,142,493	$351,363,607	$350,656,206	$350,007,924	$349,645,263	$349,319,803	$348,630,513	$347,839,468	$347,048,422	$346,257,376	$345,466,181	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,900,809	$1,896,631	$1,892,436	$1,888,626	$1,885,134	$1,883,181	$1,838,754	$1,835,126	$1,830,962	$1,826,798	$1,822,634	$1,818,470	$22,319,560
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$394,492	$393,625	$392,754	$391,964	$391,239	$390,833	$387,081	$386,317	$385,441	$384,564	$383,688	$382,811	$4,664,810
8. Investment Expenses														
a. Depreciation (e)		$791,029	$791,046	$791,046	$791,046	$791,046	$791,046	$791,046	$791,046	$791,046	$791,046	$791,046	$791,345	$9,492,832
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)		$3,086,330	$3,081,301	$3,076,236	$3,071,635	$3,067,419	$3,065,060	$3,016,881	$3,012,489	$3,007,449	$3,002,408	$2,997,368	$2,992,626	$36,477,202

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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	$359	$362	$364	$367	$370	$373	$376	$379	$381	$384	$387	$390	$393	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$954	$951	$948	$945	$943	$940	$937	$934	$931	$928	$926	$923	$920	
6. Average Net Investment		$952	$950	$947	$944	$941	$938	$936	$933	$930	$927	$924	$921	
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	$60
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	$13
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	$106

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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)	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	
3a. Less: Accumulated Depreciation	$308,182	$311,092	$314,002	$316,913	$319,823	$322,733	$325,644	$328,554	$331,464	$334,374	$337,285	$340,195	$343,105	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,133,885	$1,130,975	$1,128,064	$1,125,154	$1,122,244	$1,119,334	$1,116,423	$1,113,513	$1,110,603	$1,107,692	$1,104,782	$1,101,872	$1,098,962	
6. Average Net Investment		$1,132,430	$1,129,520	$1,126,609	$1,123,699	$1,120,789	$1,117,878	$1,114,968	$1,112,058	$1,109,148	$1,106,237	$1,103,327	$1,100,417	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,099	$6,084	$6,068	$6,052	$6,037	$6,021	$5,869	$5,854	$5,838	$5,823	$5,808	$5,792	$71,344
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,266	$1,263	$1,259	$1,256	$1,253	$1,250	$1,235	$1,232	$1,229	$1,226	$1,223	$1,219	$14,911
8. Investment Expenses														
a. Depreciation (e)		$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$34,923
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)		$10,275	$10,256	$10,237	$10,219	$10,200	$10,181	$10,015	$9,996	$9,978	$9,959	$9,941	$9,922	$121,179

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	
3a. Less: Accumulated Depreciation	$24,185,617	$24,603,293	$25,020,968	$25,438,643	$25,856,318	$26,273,993	$26,691,668	$27,109,344	$27,527,019	$27,944,694	$28,362,369	$28,780,044	$29,197,720	
3b. Less: Capital Recovery Unamortized Balance	($69,386)	($68,744)	($68,101)	($67,459)	($66,817)	($66,174)	($65,532)	($64,889)	($64,247)	($63,604)	($62,962)	($62,319)	($61,677)	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$87,125,476	$86,707,159	$86,288,841	$85,870,523	$85,452,206	$85,033,888	$84,615,570	$84,197,253	$83,778,935	$83,360,617	$82,942,300	$82,523,982	$82,105,664	
6. Average Net Investment		$86,916,317	$86,498,000	$86,079,682	$85,661,364	$85,243,047	$84,824,729	$84,406,411	$83,988,094	$83,569,776	$83,151,458	$82,733,141	$82,314,823	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$468,129	$465,876	$463,623	$461,370	$459,117	$456,864	$444,300	$442,098	$439,896	$437,694	$435,492	$433,290	$5,407,748
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$97,155	$96,687	$96,220	$95,752	$95,285	$94,817	$93,531	$93,067	$92,604	$92,140	$91,677	$91,213	$1,130,148
8. Investment Expenses														
a. Depreciation (e)		$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$5,012,102
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)		$983,602	$980,881	$978,161	$975,440	$972,719	$969,999	$956,148	$953,483	$950,817	$948,152	$945,486	$942,821	$11,557,707

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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	$4	$82,517	$1,014,501	$158,653	$220,700	$172,287	$0	$0	$0	$0	$0	$1,648,662
b. Clearings to Plant		($88,160)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,255,675	$1,167,515
c. Retirements		($88,162)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($88,162)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$107,495,932	$107,407,772	$107,407,772	$107,407,772	$107,407,772	$107,407,772	$107,407,772	$107,407,772	$107,407,772	$107,407,772	$107,407,772	$107,407,772	$108,663,448	
3a. Less: Accumulated Depreciation	$21,614,380	$21,864,586	$22,114,793	$22,364,999	$22,615,206	$22,865,412	$23,115,619	$23,365,825	$23,616,031	$23,866,238	$24,116,444	$24,366,651	$24,618,317	
3b. Less: Capital Recovery Unamortized Balance	$0	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	
4. CWIP Non-Interest Bearing	$0	$0	$4	$82,521	$1,097,022	$1,255,675	$1,476,375	$1,648,662	$1,648,662	$1,648,662	$1,648,662	$1,648,662	$392,987	
5. Net Investment (Lines 2 - 3 + 4)	$85,881,552	$85,631,348	$85,381,145	$85,213,456	$85,977,750	$85,886,197	$85,856,691	$85,778,771	$85,528,565	$85,278,359	$85,028,152	$84,777,946	$84,526,280	
6. Average Net Investment		$85,756,450	$85,506,246	$85,297,301	$85,595,603	$85,931,974	$85,871,444	$85,817,731	$85,653,668	$85,403,462	$85,153,255	$84,903,049	$84,652,113	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$461,882	$460,535	$459,409	$461,016	$462,828	$462,501	$451,729	$450,865	$449,548	$448,231	$446,914	$445,593	$5,461,050
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$95,859	$95,579	$95,345	$95,679	$96,055	$95,987	$95,095	$94,913	$94,636	$94,358	$94,081	$93,803	$1,141,389
8. Investment Expenses														
a. Depreciation (e)		$250,206	$250,206	$250,206	$250,206	$250,206	$250,206	$250,206	$250,206	$250,206	$250,206	$250,206	$251,666	$3,003,937
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)		$807,947	$806,320	$804,961	$806,901	$809,089	$808,695	$797,030	$795,984	$794,390	$792,796	$791,201	$791,062	$9,606,375

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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		$0	$0	$0	$2,105	$0	$0	$0	$0	$0	$0	$0	$0	$2,105
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$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	$4,498,509	$4,498,509	$4,498,509	$4,498,509	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	
5. Net Investment (Lines 2 - 3 + 4)	$4,498,509	$4,498,509	$4,498,509	$4,498,509	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	
6. Average Net Investment		$4,498,509	$4,498,509	$4,498,509	$4,499,561	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	$4,500,614	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$24,229	$24,229	$24,229	$24,235	$24,240	$24,240	$23,690	$23,690	$23,690	$23,690	$23,690	$23,690	$287,544
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$5,028	$5,028	$5,028	$5,030	$5,031	$5,031	$4,987	$4,987	$4,987	$4,987	$4,987	$4,987	$60,099
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)		$29,257	$29,257	$29,257	$29,264	$29,271	$29,271	$28,678	$28,678	$28,678	$28,678	$28,678	$28,678	$347,643

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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	$0	$0	$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	$25,252	$25,534	$25,816	$26,097	$26,379	$26,661	$26,943	$27,224	$27,506	$27,788	$28,070	$28,351	$28,633	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$108,921	$108,639	$108,357	$108,076	$107,794	$107,512	$107,230	$106,949	$106,667	$106,385	$106,103	$105,822	$105,540	
6. Average Net Investment		$108,780	$108,498	$108,217	$107,935	$107,653	$107,371	$107,090	$106,808	$106,526	$106,244	$105,963	$105,681	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$586	$584	$583	$581	$580	$578	$564	$562	$561	$559	$558	$556	$6,853
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$122	$121	$121	$121	$120	$120	$119	$118	$118	$118	$117	$117	$1,432
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)		$989	$987	$986	$984	$982	$980	$964	$962	$961	$959	$957	$955	$11,666

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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	$0	$0	$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	$19,050	$19,262	$19,475	$19,687	$19,900	$20,113	$20,325	$20,538	$20,750	$20,963	$21,175	$21,388	$21,600	
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)	$82,168	$81,956	$81,743	$81,531	$81,318	$81,106	$80,893	$80,681	$80,468	$80,255	$80,043	$79,830	$79,618	
6. Average Net Investment		$82,062	$81,850	$81,637	$81,425	$81,212	$80,999	$80,787	$80,574	$80,362	$80,149	$79,937	$79,724	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$442	$441	$440	$439	$437	$436	$425	$424	$423	$422	$421	$420	$5,169
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$92	$91	$91	$91	$91	$91	$90	$89	$89	$89	$89	$88	$1,080
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)		$746	$745	$744	$742	$741	$739	$727	$726	$725	$723	$722	$721	$8,801

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
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	$1,543,536	$1,583,495	$1,623,454	$1,663,413	$1,703,372	$1,743,330	$1,783,289	$1,823,248	$1,863,207	$1,903,166	$1,943,124	$1,983,083	$2,023,042	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$15,913,267	$15,873,308	$15,833,350	$15,793,391	$15,753,432	$15,713,473	$15,673,514	$15,633,556	$15,593,597	$15,553,638	$15,513,679	$15,473,720	$15,433,762	
6. Average Net Investment		$15,893,288	$15,853,329	$15,813,370	$15,773,411	$15,733,453	$15,693,494	$15,653,535	$15,613,576	$15,573,617	$15,533,659	$15,493,700	$15,453,741	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$85,601	$85,386	$85,170	$84,955	$84,740	$84,525	$82,397	$82,187	$81,977	$81,766	$81,556	$81,346	$1,001,606
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$17,766	$17,721	$17,676	$17,632	$17,587	$17,542	$17,346	$17,301	$17,257	$17,213	$17,169	$17,124	$209,333
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)		$143,325	$143,065	$142,805	$142,546	$142,286	$142,026	$139,702	$139,447	$139,193	$138,938	$138,683	$138,429	$1,690,444

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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37 - DeSoto Next Generation Solar Energy Center														
Solar														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$50,320	$0	$0	$0	$0	$50,320
b. Clearings to Plant		$515	($408)	$0	$481	($5,433)	($4,064)	$0	$0	$0	$0	$0	$0	($8,909)
c. Retirements		$0	$0	$0	$0	($5,433)	($4,064)	$0	$0	$0	$0	$0	$0	($9,497)
d. Other (a)		$15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15
2. Plant-In-Service/Depreciation Base (b)	$153,531,698	$153,532,213	$153,531,805	$153,531,805	$153,532,286	$153,526,853	$153,522,789	$153,522,789	$153,522,789	$153,522,789	$153,522,789	$153,522,789	$153,522,789	
3a. Less: Accumulated Depreciation	$41,402,609	$41,847,900	$42,293,182	$42,738,463	$43,183,744	$43,623,561	$44,064,690	$44,509,859	$44,955,027	$45,400,196	$45,845,365	$46,290,534	$46,735,703	
4. CWIP Non-Interest Bearing	$1	$1	$1	$1	$1	$1	$1	$1	$50,321	$50,321	$50,321	$50,321	$50,321	
5. Net Investment (Lines 2 - 3 + 4)	$112,129,090	$111,684,313	$111,238,623	$110,793,343	$110,348,542	$109,903,292	$109,458,099	$109,012,931	$108,618,082	$108,172,913	$107,727,744	$107,282,575	$106,837,406	
6. Average Net Investment		$111,906,701	$111,461,468	$111,015,983	$110,570,942	$110,125,917	$109,680,696	$109,235,515	$108,815,506	$108,395,497	$107,950,329	$107,505,160	$107,059,991	
a. Average ITC Balance		$31,920,369	$31,798,303	$31,676,237	$31,554,171	$31,432,105	$31,310,039	$31,187,973	$31,065,907	$30,943,841	$30,821,775	$30,699,709	$30,577,643	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$664,438	$661,804	$659,169	$656,536	$653,903	$651,269	$636,419	$633,968	$631,516	$628,933	$626,349	$623,765	$7,728,069
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$135,055	$134,519	$133,983	$133,447	$132,912	$132,376	$129,889	$129,389	$128,889	$128,361	$127,833	$127,305	$1,573,957
8. Investment Expenses														
a. Depreciation (e)		$433,090	$433,094	$433,094	$433,094	$433,063	$433,006	$432,982	$432,982	$432,982	$432,982	$432,982	$432,982	$5,196,332
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)		$1,084,375	$1,081,210	$1,078,038	$1,074,870	$1,071,670	$1,068,443	$1,051,081	$1,048,130	$1,045,179	$1,042,067	$1,038,956	$1,035,844	$12,719,862

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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	$0	$0
b. Clearings to Plant		$0	$0	$0	($14,106)	$0	$0	$0	$0	$0	$0	$0	$0	($14,106)
c. Retirements		$0	$0	$0	($14,106)	$0	$0	$0	$0	$0	$0	$0	$0	($14,106)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$70,601,750	$70,601,750	$70,601,750	$70,601,750	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	
3a. Less: Accumulated Depreciation	$18,268,753	$18,468,794	$18,668,835	$18,868,876	$19,054,727	$19,254,600	$19,454,473	$19,654,345	$19,854,218	$20,054,090	$20,253,963	$20,453,835	$20,653,708	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$52,332,997	$52,132,956	$51,932,915	$51,732,874	$51,532,917	$51,333,044	$51,133,172	$50,933,299	$50,733,426	$50,533,554	$50,333,681	$50,133,809	$49,933,936	
6. Average Net Investment		$52,232,976	$52,032,935	$51,832,894	$51,632,895	$51,432,981	$51,233,108	$51,033,235	$50,833,363	$50,633,490	$50,433,618	$50,233,745	$50,033,873	
a. Average ITC Balance		$13,667,331	$13,616,142	$13,564,953	$13,513,764	$13,462,575	$13,411,386	$13,360,197	$13,309,008	$13,257,819	$13,206,630	$13,155,441	$13,104,252	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$307,748	$306,572	$305,396	$304,220	$303,044	$301,868	$294,942	$293,789	$292,636	$291,483	$290,330	$289,177	$3,581,205
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$62,653	$62,413	$62,174	$61,934	$61,695	$61,455	$60,339	$60,103	$59,867	$59,631	$59,395	$59,159	$730,818
8. Investment Expenses														
a. Depreciation (e)		$195,649	$195,649	$195,649	$195,565	$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$2,346,356
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)		$503,179	$501,763	$500,347	$498,848	$497,349	$495,933	$487,890	$486,501	$485,112	$483,724	$482,335	$480,946	$5,903,927

(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 42-8E, pages 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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39 - Martin Next Generation Solar Energy Center														
Intermediate														
1. Investments														
a. Expenditures/Additions		($1,389,457)	$194,012	$62,949	$165,322	$107,700	$255,626	$93,433	$36,901	$36,901	$78,417	$665,396	$36,901	$344,101
b. Clearings to Plant		$479,622	($171,344)	$0	($20,729)	$0	$597,567	($11,178)	($4,910)	$0	$0	$0	$54,414	$923,443
c. Retirements		($1,010,743)	$0	$0	($18,108)	$0	$0	($11,178)	($4,910)	$0	$0	$0	$0	($1,044,939)
d. Other (a)		$54,994	($85)	($7,015)	($9,974)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($6,879)
2. Plant-In-Service/Depreciation Base (b)	$424,394,815	$424,874,437	$424,703,094	$424,703,094	$424,682,365	$424,682,365	$425,279,932	$425,268,754	$425,263,844	$425,263,844	$425,263,844	$425,263,844	$425,318,258	
3a. Less: Accumulated Depreciation	$91,249,931	$91,366,657	$92,439,416	$93,505,040	$94,549,486	$95,616,303	$96,683,837	$97,740,818	$98,803,943	$99,871,950	$100,939,956	$102,007,963	$103,076,035	
4. CWIP Non-Interest Bearing	$1,854,924	$465,467	$659,478	$722,427	$887,750	$995,449	$653,509	$746,942	$783,843	$820,744	$899,161	$1,564,557	$1,547,044	
5. Net Investment (Lines 2 - 3 + 4)	$334,999,808	$333,973,247	$332,923,157	$331,920,482	$331,020,629	$330,061,512	$329,249,604	$328,274,878	$327,243,744	$326,212,638	$325,223,048	$324,820,438	$323,789,267	
6. Average Net Investment		$334,486,528	$333,448,202	$332,421,819	$331,470,555	$330,541,071	$329,655,558	$328,762,241	$327,759,311	$326,728,191	$325,717,843	$325,021,743	$324,304,852	
a. Average ITC Balance		$94,472,353	$94,128,555	$93,784,757	$93,440,959	$93,097,161	$92,753,363	$92,409,565	$92,065,767	$91,721,969	$91,378,171	$91,034,373	$90,690,575	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,984,179	$1,977,922	$1,971,729	$1,965,941	$1,960,270	$1,954,836	$1,912,540	$1,906,584	$1,900,479	$1,894,484	$1,890,142	$1,885,692	$23,204,798
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$403,383	$402,115	$400,861	$399,690	$398,544	$397,447	$390,509	$389,300	$388,060	$386,843	$385,974	$385,082	$4,727,807
8. Investment Expenses														
a. Depreciation (e)		$1,022,919	$1,023,289	$1,023,084	$1,022,973	$1,022,862	$1,023,579	$1,024,203	$1,024,081	$1,024,051	$1,024,051	$1,024,051	$1,024,117	$12,283,261
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)		$3,008,286	$3,001,131	$2,993,478	$2,986,408	$2,979,480	$2,973,666	$2,925,056	$2,917,768	$2,910,394	$2,903,182	$2,897,972	$2,892,695	$35,389,515

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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	($36,431)	$0	$0	$0	$0	$0	$0	($36,431)
c. Retirements		$0	$0	$0	$0	$0	($36,431)	$0	$0	$0	$0	$0	$0	($36,431)
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	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	
3a. Less: Accumulated Depreciation	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,189,310	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	
4. 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)		$1,226	$1,226	$1,226	$1,226	$1,226	$1,226	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$14,550
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$255	$255	$255	$255	$255	$255	$252	$252	$252	$252	$252	$252	$3,041
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)		$1,481	$1,481	$1,481	$1,481	$1,481	$1,481	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$17,591

(a) Applicable to reserve salvage and removal cost

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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		$37,435	$724,744	$263,183	$470,974	$527,001	$974,592	$1,444,439	$1,468,271	$977,209	$779,367	$620,828	$513,171	$8,801,215
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,881,474	$6,881,474
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	$4,042,459	$4,042,459	$4,042,459	$4,042,459	$4,042,459	$4,042,459	$4,042,459	$4,042,459	$4,042,459	$4,042,459	$10,923,933	$55,390,981
3a. Less: Accumulated Depreciation	$4,041,596	$4,041,596	$4,041,596	$4,041,596	$4,041,596	$4,041,596	$4,041,596	$4,041,596	$4,041,596	$4,041,596	$4,041,596	$4,041,596	$4,119,794	$48,577,348
4. CWIP Non-Interest Bearing	$1,160,691	$1,198,127	$1,922,871	$2,186,054	$2,657,028	$3,184,029	$4,158,621	$5,603,060	$7,071,331	$8,048,540	$8,827,907	$9,448,735	$3,080,432	$57,386,732
5. Net Investment (Lines 2 - 3 + 4)	$1,161,554	$1,198,990	$1,923,734	$2,186,917	$2,657,891	$3,184,892	$4,159,484	$5,603,923	$7,072,194	$8,049,403	$8,828,770	$9,449,598	$9,884,570	$64,200,365
6. Average Net Investment		$1,180,272	$1,561,362	$2,055,325	$2,422,404	$2,921,391	$3,672,188	$4,881,703	$6,338,058	$7,560,798	$8,439,086	$9,139,184	$9,667,084	$59,838,857
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,357	$8,409	$11,070	$13,047	$15,735	$19,778	$25,696	$33,362	$39,799	$44,422	$48,107	$50,886	$316,668
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,319	$1,745	$2,297	$2,708	$3,266	$4,105	$5,409	$7,023	$8,378	$9,351	$10,127	$10,712	$66,441
8. Investment Expenses														
a. Depreciation (e)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$78,199	$78,199
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)		$7,676	$10,155	$13,367	$15,755	$19,000	$23,883	$31,106	$40,386	$48,177	$53,773	$58,234	$139,796	$461,308

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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		$2,130,441	$1,339,344	$1,306,076	$1,187,791	($21,847,416)	$1,966,916	$2,240,795	$2,828,007	$3,527,159	$1,401,586	$1,401,586	$7,946,054	$5,428,339
b. Clearings to Plant		$0	$0	$0	$0	$22,638,992	$0	$0	$537,666	$0	$0	$0	$7,937,381	$31,114,038
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)	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$39,705,092	$39,705,092	$39,705,092	$40,242,758	$40,242,758	$40,242,758	$40,242,758	$48,180,139	
3a. Less: Accumulated Depreciation	$1,083,820	$1,128,334	$1,172,848	$1,217,363	$1,261,877	$1,335,916	$1,439,480	$1,543,044	$1,647,309	$1,752,276	$1,857,242	$1,962,209	$2,076,363	
4. CWIP Non-Interest Bearing	$19,376,111	$21,506,553	$22,845,896	$24,151,972	$25,339,763	$3,492,347	$5,459,263	$7,700,058	$9,990,399	$13,517,558	$14,919,144	$16,320,730	$16,329,404	
5. Net Investment (Lines 2 - 3 + 4)	$35,358,392	$37,444,319	$38,739,149	$40,000,710	$41,143,987	$41,861,524	$43,724,876	$45,862,107	$48,585,848	$52,008,041	$53,304,660	$54,601,280	$62,433,180	
6. Average Net Investment		$36,401,355	$38,091,734	$39,369,929	$40,572,349	$41,502,755	$42,793,200	$44,793,491	$47,223,977	$50,296,945	$52,656,351	$53,952,970	$58,517,230	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$196,057	$205,161	$212,045	$218,522	$223,533	$230,483	$235,785	$248,578	$264,754	$277,173	$283,998	$308,024	$2,904,113
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$40,689	$42,579	$44,008	$45,352	$46,392	$47,834	$49,636	$52,329	$55,734	$58,349	$59,785	$64,843	$607,529
8. Investment Expenses														
a. Depreciation (e)		$44,514	$44,514	$44,514	$44,514	$74,039	$103,564	$103,564	$104,265	$104,967	$104,967	$104,967	$114,154	$992,543
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)		$281,260	$292,254	$300,567	$308,388	$343,964	$381,881	$388,984	$405,172	$425,454	$440,488	$448,750	$487,021	$4,504,185

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2018 THROUGH DECEMBER 2018

	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	$13,261	$13,458	$13,656	$13,853	$14,050	$14,247	$14,444	$14,641	$14,839	$15,036	$15,233	$15,430	$15,627	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$80,628	$80,431	$80,234	$80,037	$79,840	$79,642	$79,445	$79,248	$79,051	$78,854	$78,657	$78,459	$78,262	
6. Average Net Investment		$80,530	$80,333	$80,135	$79,938	$79,741	$79,544	$79,347	$79,150	$78,952	$78,755	$78,558	$78,361	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$434	$433	$432	$431	$429	$428	$418	$417	$416	$415	$414	$412	$5,077
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$90	$90	$90	$89	$89	$89	$88	$88	$87	$87	$87	$87	$1,061
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)		$721	$720	$718	$717	$716	$715	$703	$702	$700	$699	$698	$696	$8,504

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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	$10,004	$10,153	$10,302	$10,450	$10,599	$10,748	$10,897	$11,045	$11,194	$11,343	$11,492	$11,640	$11,789	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$60,825	$60,676	$60,527	$60,379	$60,230	$60,081	$59,932	$59,784	$59,635	$59,486	$59,337	$59,189	$59,040	
6. Average Net Investment		$60,751	$60,602	$60,453	$60,304	$60,156	$60,007	$59,858	$59,709	$59,561	$59,412	$59,263	$59,114	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$327	$326	$326	$325	$324	$323	$315	$314	$314	$313	$312	$311	$3,830
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$68	$68	$68	$67	$67	$67	$66	$66	$66	$66	$66	$66	$800
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)		$544	$543	$542	$541	$540	$539	$530	$529	$528	$527	$526	$525	$6,415

(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 42-8E, pages 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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	$375,829	$0	$0	$0	$375,829
b. Clearings to Plant		$0	$0	$0	($866)	$0	$0	$0	$0	$375,829	$0	$0	$0	$374,963
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)	$64,624	$64,624	$64,624	$64,624	$63,759	$63,759	$63,759	$63,759	$63,759	$439,587	$439,587	$439,587	$439,587	
3a. Less: Accumulated Depreciation	$6,746	$7,156	$7,567	$7,977	$8,385	$8,790	$9,194	$9,599	$10,004	$11,602	$14,394	$17,185	$19,977	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$57,878	$57,468	$57,057	$56,647	$55,374	$54,969	$54,564	$54,159	$53,754	$427,985	$425,194	$422,402	$419,611	
6. Average Net Investment		$57,673	$57,263	$56,852	$56,010	$55,171	$54,766	$54,362	$53,957	$240,870	$426,589	$423,798	$421,006	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$311	$308	$306	$302	$297	$295	$286	$284	$1,268	$2,245	$2,231	$2,216	$10,349
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$64	$64	$64	$63	$62	$61	$60	$60	$267	$473	$470	$467	$2,173
8. Investment Expenses														
a. Depreciation (e)		$410	$410	$410	$408	$405	$405	$405	$405	$1,598	$2,791	$2,791	$2,791	$13,231
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)		$785	$783	$780	$772	$764	$761	$751	$749	$3,133	$5,510	$5,492	$5,474	$25,753

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 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	$529,931	$0	$0	$0	$529,931
b. Clearings to Plant		$0	$0	$0	($2,099)	($6)	$0	$0	$0	$529,931	$0	$0	$0	$527,826
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		$0	$0	$0	$0	($6)	$0	$0	$0	$0	$0	$0	$0	($6)
2. Plant-In-Service/Depreciation Base (b)	$214,839,789	$214,839,789	$214,839,789	$214,839,789	$214,837,689	$214,837,684	$214,837,684	$214,837,684	$214,837,684	$215,367,615	$215,367,615	$215,367,615	$215,367,615	
3a. Less: Accumulated Depreciation	$27,172,649	$28,000,810	$28,828,971	$29,657,132	$30,485,287	$31,313,431	$32,141,581	$32,969,731	$33,797,881	$34,627,713	$35,459,228	$36,290,743	$37,122,258	
4. CWIP Non-Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$187,667,140	$186,838,979	$186,010,818	$185,182,657	$184,352,402	$183,524,252	$182,696,102	$181,867,953	$181,039,803	$180,739,901	$179,908,387	$179,076,872	$178,245,357	
6. Average Net Investment		$187,253,059	$186,424,898	$185,596,737	$184,767,529	$183,938,327	$183,110,177	$182,282,027	$181,453,878	$180,889,852	$180,324,144	$179,492,629	$178,661,114	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,008,540	$1,004,080	$999,619	$995,153	$990,687	$986,227	$959,499	$955,139	$952,170	$949,193	$944,816	$940,439	$11,685,563
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$209,311	$208,386	$207,460	$206,533	$205,606	$204,681	$201,987	$201,069	$200,444	$199,817	$198,896	$197,974	$2,442,164
8. Investment Expenses														
a. Depreciation (e)		$828,161	$828,161	$828,161	$828,155	$828,150	$828,150	$828,150	$828,150	$829,832	$831,515	$831,515	$831,515	$9,949,615
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)		$2,046,013	$2,040,627	$2,035,240	$2,029,842	$2,024,443	$2,019,057	$1,989,635	$1,984,358	$1,982,447	$1,980,525	$1,975,226	$1,969,928	$24,077,342

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% 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 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		($3,589,212)	$2,307,053	$1,734,958	$2,475,785	$1,359,075	$18,073,023	$3,369,176	$3,369,176	$3,369,176	$3,369,176	$3,369,176	$6,738,351	$45,944,912
b. Clearings to Plant		($56,167)	($4,227)	$0	($927)	$5,154	$0	$0	$0	$0	$0	$0	$7,874,899	$7,818,732
c. Retirements		($56,167)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($56,167)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$260,558	$204,391	$200,164	$200,164	$199,237	$204,391	$204,391	$204,391	$204,391	$204,391	$204,391	$204,391	$8,079,290	
3a. Less: Accumulated Depreciation	$4,101	$4,358	$4,613	$4,864	$5,116	$5,370	$5,627	$5,884	$6,141	$6,398	$6,656	$6,913	$16,327	
3b. Less: Capital Recovery Unamortized Balance	$0	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	
4. CWIP Non-Interest Bearing	$24,187,348	$20,598,136	$22,905,189	$24,640,147	$27,115,931	$28,475,006	$46,548,029	$49,917,205	$53,286,381	$56,655,557	$60,024,733	$63,393,909	$62,257,361	
5. Net Investment (Lines 2 - 3 + 4)	$24,443,805	$20,854,336	$23,156,908	$24,891,613	$27,366,220	$28,730,195	$46,802,960	$50,171,879	$53,540,798	$56,909,717	$60,278,636	$63,647,554	$70,376,491	
6. Average Net Investment		$22,649,071	$22,005,622	$24,024,260	$26,128,916	$28,048,207	$37,766,577	$48,487,420	$51,856,339	$55,225,257	$58,594,176	$61,963,095	$67,012,023	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$121,987	$118,522	$129,394	$140,730	$151,067	$203,410	$255,229	$272,962	$290,695	$308,429	$326,162	$352,739	$2,671,326
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$25,317	$24,598	$26,854	$29,207	$31,352	$42,215	$53,729	$57,462	$61,195	$64,928	$68,661	$74,256	$559,776
8. Investment Expenses														
a. Depreciation (e)		$257	$255	$252	$251	$254	$257	$257	$257	$257	$257	$257	$9,415	$12,226
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)		$147,562	$143,374	$156,500	$170,188	$182,673	$245,883	$309,215	$330,681	$352,148	$373,614	$395,081	$436,409	$3,243,328

(a) Applicable to reserve salvage and removal cost

(b) 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 65-67.

(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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-8E, pages 65-67.

(f) Applicable amortization period(s). See Form 42-8E, pages 65-67.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. 2018 period of 6.557% based on the May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period of 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Jun. 2018 period of 1.716% based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period of 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-8E

JANUARY 2018 THROUGH DECEMBER 2018

	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. 254.900 Other Regulatory Liabilities-Gains	($885)	($857)	($829)	($800)	($772)	($763)	($734)	($706)	($678)	($650)	($621)	($593)	($565)	
2. Total Working Capital	($885)	($857)	($829)	($800)	($772)	($763)	($734)	($706)	($678)	($650)	($621)	($593)	($565)	
3. Average Net Working Capital Balance		($871)	($843)	($815)	($786)	($767)	($749)	($720)	($692)	($664)	($635)	($607)	($579)	
4. Return on Average Net Working Capital Balance														
a. Equity Component grossed up for taxes [a]	($7)	($5)	($5)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($3)	($3)	($3)	
b. Debt Component [b]	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	
5. Total Return Component [e]	($8)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($4)	($4)	($4)	($4)	($57)
6. Expense Dr(Cr)														
a. 411.800 Gains from Dispositions of Allowances	($119,547)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	
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) [f]	($119,547)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($28)	($339)
8. Total System Recoverable Expenses (Lines 5 + 7)	($119,555)	($34)	($34)	($34)	($33)	($33)	($33)	($33)	($33)	($33)	($32)	($32)	($32)	
a. Recoverable Costs Allocated to Energy	($119,555)	($34)	($34)	($34)	($33)	($33)	($33)	($33)	($33)	($33)	($32)	($32)	($32)	
b. Recoverable Costs Allocated to Demand														
9. Energy Jurisdictional Factor	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	
10. Demand Jurisdictional Factor	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	
11. Retail Energy-Related Recoverable Costs [c]	($113,448)	($32)	($32)	($32)	($32)	($32)	($31)	($31)	($31)	($31)	($31)	($31)	($30)	
12. Retail Demand-Related Recoverable Costs [d]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
13. Total Jurisdictional Recoverable Costs (Lines 11 + 12)	($113,448)	($32)	($32)	($32)	($32)	($32)	($31)	($31)	($31)	($31)	($31)	($31)	($30)	($376)

[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. 2018 period is 4.8251%, based on May 2017 Earning Surveillance Report and reflects a 10.55% return on equity, and the Equity Component for the Jul. – Dec. 2018 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

[b] The Debt Component for the Jan. – Jun. 2018 period is 1.3413% is based on the May 2017 Earning Surveillance Report and the Debt Component for the Jul. – Dec. 2018 period is 1.3297% based on the May 2018 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
CALCULATION OF THE ACTUAL ESTIMATED AMOUNT FOR THE PERIOD

2018 Depreciation Schedule **FORM 42-8E**

Project	Class ID	Plant	Unit	Utility	Depr. Rate / Amort. Period	Balance as of Dec-17	Balance as of Dec-18
002-LOW NOX BURNER TECHNOLOGY	02 - Steam Generation Plant	Turkey Pt	Turkey Pt U1	31200	CRS	-	-
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	31650	5-Year	58,207	58,207
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin	Martin Comm	31670	7-Year	66,897	66,897
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin	Martin Comm U1&2	31200	4.45%	31,632	31,632
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin	Martin U1	31100	2.68%	36,811	36,811
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin	Martin U1	31200	4.53%	338,939	399,323
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin	Martin U2	31100	2.39%	36,845	36,845
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin	Martin U2	31200	4.64%	335,746	335,746
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	515,653	515,653
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP - Comm	31100	CRS	43,193	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U1	31200	CRS	780	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U2	31200	CRS	780	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34100	2.20%	58,860	58,860
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34500	1.60%	34,502	34,502
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 Lauderdale	FtLauderdale U4	34300	4.11%	441,310	438,897
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale U5	34300	5.00%	556,314	556,425
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Ft Myers	FtMyers U2	34300	3.46%	368,561	368,561
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%	499,129	727,809
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin	Martin U4	34300	3.92%	491,342	720,022
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						5,822,787	6,293,477
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%	771,705	771,705
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin	Martin Comm	31200	4.45%	94,329	94,209
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin	Martin Comm U1&2	31100	2.52%	824,065	824,065
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin	Martin U1	31100	2.68%	261,417	261,417
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin	Martin U2	31100	2.39%	85,078	85,078
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP - Comm	31100	CRS	42,091	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP - Comm	31200	CRS	2,292	-
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 SC Peaker	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	7,174,603
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total						13,527,336	14,819,595
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 Comm	31670	7-Year	21,347	21,347
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin	Martin Comm	31600	3.79%	23,107	23,107
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin	Martin Comm	31650	5-Year	116,547	181,542
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin	Martin Comm	31670	7-Year	339,743	298,813
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	Ft Lauderdale	FtLauderdale Comm	34100	2.20%	363,996	364,027
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	08 - General Plant	General Plant	General Plant	39190	33.33%	2,291	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total						937,244	959,049
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	2.07%	689	689
012-SCHERER DISCHARGE PIPELINE Total						854,324	854,324
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin	Martin U1	31200	4.53%	367,906	367,906
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin	Martin U2	31200	4.64%	403,671	403,671
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total						771,577	771,577
021-ST.LUCIE TURTLE NETS	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	6,909,559	6,909,559
021-ST.LUCIE TURTLE NETS Total						6,909,559	6,909,559
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Manatee	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%	574,162	574,162
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin	Martin Comm	31500	3.57%	34,755	34,755
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin	Martin Comm U1&2	31100	2.52%	-	-
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

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

2018 Depreciation Schedule **FORM 42-8E**

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%	977,935	988,529
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32570	7-Year	-	243,990
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32570	7-Year	-	-
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
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 Lauderdale	FtLauderdale U4	34300	4.11%		-
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	34300	3.46%	49,727	49,727
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U3 SC Peaker	34500	3.40%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin	Martin Comm U3&4	34100	2.24%	523,498	523,498
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	Sanford	Sanford Comm	34100	2.40%	288,383	288,383
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Radial	Radial	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	1,207,640
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	2.04%	177,982	3,786,256
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%	3,298,168	3,303,417
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						**16,530,675**	**20,463,782**
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%		-
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	16,304,710	16,342,411
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	15,277,025	15,315,595
024-GAS REBURN Total						**31,581,736**	**31,658,006**
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**	**115,446.69**
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	Cape Canaveral	CapeCana Comm CC	34100	2.69%	766,645	767,152
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	Cape Canaveral	CapeCanaveral Comm	34100	2.69%	-	-
028-CWA 316B PHASE II RULE Total						**766,645**	**767,152.37**
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%	20,461,529	20,461,529
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	Martin	Martin Comm	31400	3.48%	287,258	287,258
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin Comm U1&2	31200	4.45%	518,275	518,275
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin U1	31200	4.53%	19,504,077	19,504,077
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin U1	31400	3.35%	7,499,710	7,499,710
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin U2	31200	4.64%	20,224,580	20,224,580
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin U2	31400	4.79%	7,477,120	7,477,120
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer Comm U3&4	31200	2.32%	79,730	406,783
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	12,775	12,775
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U1	31200	CRS	27,746,239	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U1	31500	CRS	446,692	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U1	31600	CRS	9,138	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U2	31200	CRS	26,534,954	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U2	31500	CRS	426,220	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U2	31600	CRS	9,591	-
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						**524,714,132**	**469,868,352**
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer	Scherer Comm U3&4	31200	2.32%	(1,234,039)	(1,234,037)
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	108,641,809	109,897,484
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U1	31200	CRS	70,087	-
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U2	31200	CRS	18,075	-
033-CLEAN AIR MERCURY RULE-CAMR Total						**107,495,932**	**108,663,447.52**
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**	**235,391.32**
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%	5,264,052	5,263,916
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34300	3.36%	115,292,510	115,292,583
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	34600	3.30%	-	-
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34630	3-Year	8,469	8,469
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34650	5-Year	50,315	51,031
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34670	7-Year	161,143	151,580
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

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

2018 Depreciation Schedule **FORM 42-8E**

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						**153,531,698**	**153,522,789**
038-SPACE COAST SOLAR PROJECT	01 - Intangible Plant	Intangible Plant	Intangible Plant	30300	30-year	6,359,027	6,359,027
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34100	3.45%	3,889,496	3,889,496
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	35,202
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast	Space Coast Solar	34670	7-Year	14,106	-
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						**70,601,750**	**70,587,644**
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%	20,745,276	20,745,276
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34300	2.88%	397,113,924	398,071,563
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34500	2.99%	4,122,852	4,122,852
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34600	2.85%	1,299	1,299
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34650	5-Year	11,178	-
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	Martin Solar	34670	7-Year	134,433	129,522
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	08 - General Plant	General Plant	General Plant	39420	7-Year	13,666	-
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	General Plant	39720	7-Year	4,442	-
039-MARTIN SOLAR PROJECT Total						**424,394,815**	**425,318,258**
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	Ft Lauderdale	Dania Beach Unit 7	34300	44-Month	-	6,881,474
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	Ft Myers	FtMyers U2	34300	0.00%	-	-
041-PRV MANATEE HEATING SYSTEM	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	0.00%	276,404	276,404
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36100	0.00%	73,267	73,267
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36200	0.00%	471,542	471,542
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36410	0.00%	137,247	137,247
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36420	0.00%	36,431	-
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36500	0.00%	307,599	307,599
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36660	0.00%	221,326	221,326
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36760	0.00%	168,995	168,995
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Distribution	Mass Distribution Plant	36910	0.00%	607	607
041-PRV MANATEE HEATING SYSTEM Total						**5,735,878**	**12,580,920**
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32100	3.13%	17,066,101	44,687,786
042-PTN COOLING CANAL MONITORING SYS	05 - Other Generation Plant	Turkey Pt	Turkey Pt U5	34100	2.33%		3,492,353
042-PTN COOLING CANAL MONITORING SYS Total						**17,066,101**	**48,180,139**
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**	**164,718.55**
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	155,747	1,059,420
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	44,989,219	44,989,219
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%	51,910,750	51,910,750
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%	1,071,311	1,071,311
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin	Martin U1	31200	4.53%	47,137,592	47,136,708
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin	Martin U1	31500	3.12%	4,322,420	4,322,420
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin	Martin U1	31600	3.81%	1,012,007	1,012,007
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin	Martin U2	31200	4.64%	48,445,547	48,445,547
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin	Martin U2	31500	3.56%	4,449,270	4,449,270
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin	Martin U2	31600	4.31%	1,070,760	1,070,760
045-800 MW UNIT ESP PROJECT Total						**214,904,413**	**215,807,202**
050 - Steam Electric Effluent Rev	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%		-
050 - Steam Electric Effluent Rev Total							**-**
054-Coal Combustion Residuals	02 - Steam Generation Plant	Scherer	Scherer Comm	31100	1.51%	204,391	199,237
054-Coal Combustion Residuals	02 - Steam Generation Plant	Scherer	Scherer U4	31200	2.79%	-	7,880,053
054-Coal Combustion Residuals	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP - Comm	31100	CRS	56,167	-
054-Coal Combustion Residuals Total						**260,558**	**8,079,290**
Grand Total						**1,617,401,132**	**1,617,098,537**

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

FORM 42-9E

Equity @ 10.55%

CAPITAL STRUCTURE AND COST RATES PER MAY 2017 EARNINGS SURVEILLANCE REPORT

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

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

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

DEBT COMPONENTS:	
LONG TERM DEBT	1.2592%
SHORT TERM DEBT	0.0501%
CUSTOMER DEPOSITS	0.0285%
TAX CREDITS -WEIGHTED	0.0035%
TOTAL DEBT	**1.3413%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8119%
TAX CREDITS -WEIGHTED	0.0132%
TOTAL EQUITY	**4.8251%**
TOTAL	6.1663%
PRE-TAX EQUITY	7.8552%
PRE-TAX TOTAL	9.1965%

Note:

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

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

FORM 42-9E

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)

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

REVISED FORM: 42-1A

JANUARY 2017 THROUGH DECEMBER 2017

	2017
1. Over/(Under) Recovery for the Current Period (Form 42-2A, Line 5)	$59,779,725
2. Interest Provision (Form 42-2A, Line 6)	$578,057
3. Total	$60,357,782
4. Actual/Estimated Over/(Under) Recovery for the Same Period[(a)]	$28,365,707
5. Interest Provision	$431,995
6. Total	$28,797,701
7. Net True-Up for the period Over/(Under)	$31,560,081

[(a)] Approved in Order No. PSC-2018-0014-FOF-EI issued on January 5, 2018

Note: Totals may not add due to rounding

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 13
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Renae B. Deaton RBD-3

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

REVISED FORM: 42-2A

JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1. ECRC Revenues (net of Revenue Taxes)	$19,020,904	$16,158,964	$17,092,622	$18,716,891	$21,244,550	$23,622,657	$24,983,373	$24,781,611	$23,728,803	$22,522,607	$18,989,331	$18,243,961	$249,106,274
2. True-up Provision	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$949,348	$11,392,170
3. ECRC Revenues Applicable to Period (Lines 1 + 2)	$19,970,251	$17,108,312	$18,041,970	$19,666,238	$22,193,897	$24,572,004	$25,932,720	$25,730,959	$24,678,151	$23,471,955	$19,938,679	$19,193,308	$260,498,444
4. Jurisdictional ECRC Costs													
a. O&M Activities (Form 42-5A, Line 9)	$1,801,543	$2,530,350	$2,348,467	$2,515,814	$2,669,478	$3,246,176	$3,456,368	$3,283,451	$2,266,734	$3,296,207	$3,212,958	$3,127,332	$33,754,880
b. Capital Investment Projects (Form 42-7A, Line 9)	$14,022,596	$14,001,320	$13,978,047	$13,954,361	$13,929,761	$13,906,445	$13,881,632	$13,861,558	$13,847,213	$13,845,913	$13,848,488	$13,886,505	$166,963,839
c. Total Jurisdictional ECRC Costs	$15,824,140	$16,531,670	$16,326,514	$16,470,175	$16,599,239	$17,152,621	$17,338,000	$17,145,009	$16,113,947	$17,142,120	$17,061,446	$17,013,838	$200,718,719
5. Over/(Under) Recovery (Line 3 - Line 4c)	$4,146,112	$576,642	$1,715,456	$3,196,063	$5,594,658	$7,419,383	$8,594,720	$8,585,950	$8,564,204	$6,329,835	$2,877,232	$2,179,470	$59,779,725
6. Interest Provision (Form 42-3A, Line 10)	$22,425	$22,021	$25,356	$30,036	$32,824	$41,543	$51,529	$58,048	$53,394	$60,885	$81,515	$98,480	$578,057
7. Prior Periods True-Up to be (Collected)/Refunded	$11,392,170	$14,611,359	$14,260,674	$15,052,139	$17,328,891	$22,007,026	$28,518,604	$36,215,506	$43,910,156	$51,578,407	$57,019,779	$59,029,179	$11,392,170
a. Deferred True-Up (Form 42-1A, Line 7) [a]	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	$23,872,381	
8. True-Up Collected /(Refunded) (See Line 2)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($949,348)	($11,392,170)
9. End of Period True-Up (Lines 5+6+7+7a+8)	$38,483,740	$38,133,055	$38,924,520	$41,201,272	$45,879,407	$52,390,985	$60,087,887	$67,782,537	$75,450,788	$80,892,160	$82,901,560	$84,230,163	$60,357,782
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)	$38,483,740	$38,133,055	$38,924,520	$41,201,272	$45,879,407	$52,390,985	$60,087,887	$67,782,537	$75,450,788	$80,892,160	$82,901,560	$84,230,163	$60,357,782

[a] From FPL's 2016 Final True-up filed on April 3, 2017.

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

REVISED FORM: 42-3A

JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1. Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$35,264,551	$38,483,740	$38,133,055	$38,924,520	$41,201,272	$45,879,407	$52,390,985	$60,087,887	$67,782,537	$75,450,788	$80,892,160	$82,901,560	N/A
2. Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	$38,461,315	$38,111,034	$38,899,163	$41,171,236	$45,846,582	$52,349,442	$60,036,357	$67,724,489	$75,397,394	$80,831,275	$82,820,045	$84,131,683	N/A
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	$73,725,866	$76,594,774	$77,032,219	$80,095,756	$87,047,854	$98,228,849	$112,427,342	$127,812,375	$143,179,930	$156,282,063	$163,712,205	$167,033,243	N/A
4. Average True-Up Amount (Line 3 x 1/2)	$36,862,933	$38,297,387	$38,516,109	$40,047,878	$43,523,927	$49,114,425	$56,213,671	$63,906,188	$71,589,965	$78,141,031	$81,856,102	$83,516,621	N/A
5. Interest Rate (First Day of Reporting Month)	0.72000%	0.74000%	0.64000%	0.94000%	0.86000%	0.95000%	1.08000%	1.12000%	1.06000%	0.73000%	1.14000%	1.25000%	N/A
6. Interest Rate (First Day of Subsequent Month)	0.74000%	0.64000%	0.94000%	0.86000%	0.95000%	1.08000%	1.12000%	1.06000%	0.73000%	1.14000%	1.25000%	1.58000%	N/A
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	1.46000%	1.38000%	1.58000%	1.80000%	1.81000%	2.03000%	2.20000%	2.18000%	1.79000%	1.87000%	2.39000%	2.83000%	N/A
8. Average Interest Rate (Line 7 x 1/2)	0.73000%	0.69000%	0.79000%	0.90000%	0.90500%	1.01500%	1.10000%	1.09000%	0.89500%	0.93500%	1.19500%	1.41500%	N/A
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.06083%	0.05750%	0.06583%	0.07500%	0.07542%	0.08458%	0.09167%	0.09083%	0.07458%	0.07792%	0.09958%	0.11792%	N/A
10. Interest Provision for the Month (Line 4 x Line 9)	$22,425	$22,021	$25,356	$30,036	$32,824	$41,543	$51,529	$58,048	$53,394	$60,885	$81,515	$98,480	$578,057

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

FORM: 42-4A

JANUARY 2017 THROUGH DECEMBER 2017
VARIANCE REPORT OF O&M ACTIVITES

(1)	(2)	(3)	(4)	(5)
O&M Projects	ECRC - 2017 Final True-Up [a]	ECRC - 2017 Actual/Estimated [b]	Dif. ECRC - 2017 Actual/Estimated [c]	% Dif. ECRC - 2017 Actual/Estimated [d]
1 - Air Operating Permit Fees	$382,458	$342,223	$40,235	12%
3a - Continuous Emission Monitoring Systems	$419,613	$419,642	($29)	(0%)
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,937,349	$1,615,250	$322,098	20%
8a - Oil Spill Clean-up/Response Equipment	$262,890	$249,543	$13,347	5%
NA-Amortization of Gains on Sales of Emissions Allowances	($123,492)	($4,274)	($119,218)	2,789%
14 - NPDES Permit Fees	$69,200	$74,435	($5,235)	(7%)
17a - Disposal of Non-Containerized Liquid Waste	($13,821)	$5,000	($18,821)	(376%)
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$2,063,849	$2,751,121	($687,272)	(25%)
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$901,320	$1,021,093	($119,773)	(12%)
21 - St. Lucie Turtle Nets	$163,228	$110,000	$53,228	48%
22 - Pipeline Integrity Management	$171,592	$401,500	($229,908)	(57%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$831,037	$920,034	($88,997)	(10%)
24 - Manatee Reburn	$237,869	$341,784	($103,915)	(30%)
27 - Lowest Quality Water Source	$134,714	$149,831	($15,116)	(10%)
28 - CWA 316(b) Phase II Rule	$1,166,528	$1,163,160	$3,367	0%
29 - SCR Consumables	$383,767	$700,469	($316,702)	(45%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$4,220,907	$4,121,591	$99,316	2%
33 - MATS Project	$1,835,382	$2,050,981	($215,598)	(11%)
35 - Martin Plant Drinking Water System Compliance	$39,316	$50,000	($10,684)	(21%)
37 - DeSoto Next Generation Solar Energy Center	$520,796	$723,025	($202,229)	(28%)
38 - Space Coast Next Generation Solar Energy Center	$200,413	$249,245	($48,832)	(20%)
39 - Martin Next Generation Solar Energy Center	$5,197,449	$3,804,619	$1,392,830	37%
41 - Manatee Temporary Heating System	$2,004,557	$2,375,922	($371,365)	(16%)
42 - Turkey Point Cooling Canal Monitoring Plan	$11,150,044	$37,649,926	($26,499,882)	(70%)
45 - 800 MW Unit ESP	$631,002	$746,628	($115,626)	(15%)
47 - NPDES Permit Renewal Requirements	$189,569	$122,677	$66,892	55%
48 - Industrial Boiler MACT	$76,538	$38,000	$38,538	101%
50 - Steam Electric Effluent Guidelines Revised Rules	$363,379	$164,576	$198,803	121%
51 - Gopher Tortoise Relocations	$19,514	$39,000	($19,486)	(50%)
52 - Numeric Nutrient Criteria Water Quality Standards in Florida	$4,368	$4,368	$0	(0%)
54 - Coal Combustion Residuals	$0	$9,600	($9,600)	(100%)
Total	$35,441,333	$62,410,969	($26,969,636)	(43%)

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

[b] The approved projected amount in accordance with FPSC Order No. PSC-2018-0014-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: 42-4A

JANUARY 2017 THROUGH DECEMBER 2017

VARIANCE REPORT OF O&M ACTIVITES

(1)	(2)	(3)	(4)	(5)
	ECRC - 2017 Final True-Up	ECRC - 2017 Estimated/Actual Filing	Dif. ECRC - 2017 Estimated/Actual Filing	% Dif. ECRC - 2017 Estimated/Actual Filing
2. Total of O&M Activities	$35,441,333	$62,410,969	($26,969,636)	(43%)
3. Recoverable Costs Allocated to Energy	$21,391,175	$48,999,435	($27,608,260)	(56%)
4a. Recoverable Costs Allocated to CP Demand	$11,986,309	$10,660,413	$1,325,896	12%
4b. Recoverable Costs Allocated to GCP Demand	$2,063,849	$2,751,121	($687,272)	(25%)
7. Jurisdictional Energy Recoverable Costs	$20,298,454	$46,496,407	($26,197,953)	(56%)
8a. Jurisdictional CP Demand Recoverable Costs	$11,392,577	$10,132,358	$1,260,219	12%
8b. Jurisdictional GCP Demand Recoverable Costs	$2,063,849	$2,751,121	($687,272)	(25%)
9. Total Jurisdictional Recoverable Costs for O&M Activities	$33,754,880	$59,379,886	($25,625,006)	(43%)

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

FORM: 42-5A

JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
O&M Projects	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
1 - Air Operating Permit Fees	$9,485	$25,096	$67,825	$25,096	$26,177	$26,177	$26,177	$26,721	$26,177	$35,561	$43,982	$43,982	$382,458
3a - Continuous Emission Monitoring Systems	$37,685	$28,998	$37,794	$22,196	$19,871	$17,562	$28,949	$18,772	$38,598	$23,364	$65,080	$80,746	$419,613
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	$16,831	$132,184	$71,568	$285,581	$329,168	$382,063	$8,695	$51,913	$1,441	$164,960	$184,622	$308,324	$1,937,349
8a - Oil Spill Clean-up/Response Equipment	$15,351	$13,950	$12,397	$12,872	$10,233	$43,345	$13,724	$7,023	$10,966	$5,861	$45,500	$71,667	$262,890
14 - NPDES Permit Fees	$69,200	$0	$5,235	$0	$0	$0	$0	$0	$0	$3,600	$0	($8,835)	$69,200
17a - Disposal of Non-Containerized Liquid Waste	$0	$0	$0	$0	$0	$0	$179	($14,000)	$0	$0	$0	$0	($13,821)
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$55,094	$61,635	$210,024	$180,754	$289,287	$269,384	$165,748	$139,709	$168,405	$105,769	$176,703	$241,338	$2,063,849
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$18,563	$53,336	$41,468	$278,043	$63,918	$79,995	$21,272	$30,417	$71,812	$29,660	$27,533	$185,301	$901,320
21 - St. Lucie Turtle Nets	$0	$0	$0	$0	$0	$39,058	$12,965	$13,815	$47,919	$22,496	$13,815	$13,159	$163,228
NA-Amortization of Gains on Sales of Emissions Allowances	($347)	($347)	($347)	($347)	($361)	($361)	($361)	($374)	($367)	($367)	($367)	($119,547)	($123,492)
22 - Pipeline Integrity Management	$0	$17,905	$189	$0	$997	$176	$0	$0	$0	$50	$134,271	$18,004	$171,592
23 - SPCC - Spill Prevention, Control & Countermeasures	$56,158	$75,834	$93,234	$101,375	$114,909	$21,586	$118,901	$128,528	$89,141	($57,008)	$56,483	$31,897	$831,037
24 - Manatee Reburn	$20,249	$25,790	$6,754	$4,537	$13,489	$835	$27,795	$0	$22,522	$5,158	$0	$110,741	$237,869
27 - Lowest Quality Water Source	$10,623	$12,141	$11,710	$11,046	$12,070	$11,226	$11,074	$10,880	$10,925	$11,047	$10,899	$11,075	$134,714
28 - CWA 316(b) Phase II Rule	($5,374)	$89,956	$107,796	$136,924	$102,989	$157,008	$37,440	$140,537	$112,902	$92,899	$98,912	$94,538	$1,166,528
29 - SCR Consumables	$16,463	$23,215	$62,633	$10,939	$24,480	$60,168	$50,197	$29,815	$41,922	$21,781	$15,784	$26,368	$383,767
31 - Clean Air Interstate Rule (CAIR) Compliance	$388,814	$413,509	$197,052	$317,977	$345,970	$391,011	$437,525	$362,557	$284,288	$329,274	$375,505	$377,425	$4,220,907
33 - MATS Project	$31,065	$88,713	$243,346	$140,448	$112,657	$169,203	$172,733	$219,470	$221,799	$108,908	$119,543	$207,497	$1,835,382
35 - Martin Plant Drinking Water System Compliance	$7,498	$135	$250	$7,843	$6,075	$2,500	$3,359	$420	$8,461	$53	$90	$2,633	$39,316
37 - DeSoto Next Generation Solar Energy Center	$36,685	$69,101	$41,035	$32,914	$100,216	$34,674	$28,317	$48,479	$21,617	$37,319	$26,999	$43,440	$520,796
38 - Space Coast Next Generation Solar Energy Center	$8,428	$17,888	$11,065	$8,555	$8,594	$6,982	$19,961	$26,549	$10,880	$35,970	$18,569	$26,972	$200,413
39 - Martin Next Generation Solar Energy Center	$406,187	$407,297	$390,803	$214,141	$247,497	$523,880	$867,537	$418,049	$218,439	$365,331	$470,721	$667,568	$5,197,449
41 - Manatee Temporary Heating System	$1,274	$15,154	$45,062	$10,923	$230,066	$199,496	$408,999	$417,557	$239,891	$236,334	$181,835	$17,965	$2,004,557
42 - Turkey Point Cooling Canal Monitoring Plan	$574,833	$867,533	$730,260	$722,895	$662,082	$918,451	$1,102,614	$1,285,626	$614,557	$1,782,810	$1,162,512	$725,873	$11,150,044
45 - 800 MW Unit ESP	$61,598	$140,176	$84,115	$81,545	$47,763	$36,766	$30,383	$28,732	$27,592	$30,137	$24,635	$37,561	$631,002
47 - NPDES Permit Renewal Requirements	($1,052)	$1	$0	$18,558	$3,301	$0	$10,412	$21,614	$44,322	$25,656	$38,918	$27,839	$189,569
48 - Industrial Boiler MACT	$0	$0	$0	$0	$0	$0	$0	$0	$10,763	$21,232	$25,325	$19,217	$76,538
50 - Steam Electric Effluent Guidelines Revised Rules	$59,135	$82,486	($13,301)	$14,891	$24,505	$13,165	$27,011	$31,769	$20,685	$28,827	$56,640	$17,566	$363,379
51 - Gopher Tortoise Relocations	$0	$0	$0	$0	$0	$0	$0	$6,594	$12,920	$0	$0	$0	$19,514
52 - Numeric Nutrient Criteria Water Quality Standards in Florida	$0	$0	$4,368	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,368
54 - Coal Combustion Residuals	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total of O&M Activities	$1,894,445	$2,661,684	$2,462,337	$2,639,706	$2,795,955	$3,404,349	$3,631,607	$3,451,170	$2,378,579	$3,466,681	$3,374,508	$3,280,313	$35,441,333

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

FORM: 42-5A

JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)
Method of Classification	Total	Energy	CP Demand	GCP Demand
1 - Air Operating Permit Fees	$382,458	$382,458	$0	$0
3a - Continuous Emission Monitoring Systems	$419,613	$419,613	$0	$0
5a - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,937,349	$0	$1,937,349	$0
8a - Oil Spill Clean-up/Response Equipment	$262,890	$262,890	$0	$0
14 - NPDES Permit Fees	$69,200	$0	$69,200	$0
17a - Disposal of Non-Containerized Liquid Waste	($13,821)	($13,821)	$0	$0
19a - Substation Pollutant Discharge Prevention & Removal - Distribution	$2,063,849	$0	$0	$2,063,849
19b - Substation Pollutant Discharge Prevention & Removal - Transmission	$901,320	$0	$901,320	$0
21 - St. Lucie Turtle Nets	$163,228	$0	$163,228	$0
NA-Amortization of Gains on Sales of Emissions Allowances	($123,492)	($123,492)	$0	$0
22 - Pipeline Integrity Management	$171,592	$0	$171,592	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	$831,037	$0	$831,037	$0
24 - Manatee Reburn	$237,869	$237,869	$0	$0
27 - Lowest Quality Water Source	$134,714	$0	$134,714	$0
28 - CWA 316(b) Phase II Rule	$1,166,528	$0	$1,166,528	$0
29 - SCR Consumables	$383,767	$383,767	$0	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	$4,220,907	$4,220,907	$0	$0
33 - MATS Project	$1,835,382	$1,835,382	$0	$0
35 - Martin Plant Drinking Water System Compliance	$39,316	$0	$39,316	$0
37 - DeSoto Next Generation Solar Energy Center	$520,796	$0	$520,796	$0
38 - Space Coast Next Generation Solar Energy Center	$200,413	$0	$200,413	$0
39 - Martin Next Generation Solar Energy Center	$5,197,449	$0	$5,197,449	$0
41 - Manatee Temporary Heating System	$2,004,557	$2,004,557	$0	$0
42 - Turkey Point Cooling Canal Monitoring Plan	$11,150,044	$11,150,044	$0	$0
45 - 800 MW Unit ESP	$631,002	$631,002	$0	$0
47 - NPDES Permit Renewal Requirements	$189,569	$0	$189,569	$0
48 - Industrial Boiler MACT	$76,538	$0	$76,538	$0
50 - Steam Electric Effluent Guidelines Revised Rules	$363,379	$0	$363,379	$0
51 - Gopher Tortoise Relocations	$19,514	$0	$19,514	$0
52 - Numeric Nutrient Criteria Water Quality Standards in Florida	$4,368	$0	$4,368	$0
54 - Coal Combustion Residuals	$0	$0	$0	N/A
Total of O&M Activities	$35,441,333	$21,391,175	$11,986,309	$2,063,849

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

FORM: 42-5A

JANUARY 2017 THROUGH DECEMBER 2017
O&M ACTIVITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	2017
2. Total of O&M Activities	$1,894,445	$2,661,684	$2,462,337	$2,639,706	$2,795,955	$3,404,349	$3,631,607	$3,451,170	$2,378,579	$3,466,681	$3,374,508	$3,280,313	$35,441,333
3. Recoverable Costs Allocated to Energy	$1,156,471	$1,641,787	$1,486,893	$1,349,080	$1,492,428	$1,862,652	$2,298,914	$2,381,897	$1,527,947	$2,578,821	$2,034,009	$1,580,277	$21,391,175
4a. Recoverable Costs Allocated to CP Demand	$682,881	$958,263	$765,420	$1,109,871	$1,014,240	$1,272,313	$1,166,945	$929,564	$682,227	$782,091	$1,163,797	$1,458,698	$11,986,309
4b. Recoverable Costs Allocated to GCP Demand	$55,094	$61,635	$210,024	$180,754	$289,287	$269,384	$165,748	$139,709	$168,405	$105,769	$176,703	$241,338	$2,063,849
5.Retail Energy Jurisdictional Factor	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	
6a. Retail CP Demand Jurisdictional Factor	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	
6b. Retail GCP Demand Jurisdictional	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 Energy Recoverable Costs [a]	$1,097,395	$1,557,920	$1,410,938	$1,280,165	$1,416,191	$1,767,502	$2,181,479	$2,260,223	$1,449,895	$2,447,087	$1,930,106	$1,499,552	$20,298,454
8a. Jurisdictional CP Demand Recoverable Costs [b]	$649,055	$910,796	$727,506	$1,054,895	$964,000	$1,209,290	$1,109,141	$883,519	$648,434	$743,351	$1,106,149	$1,386,443	$11,392,577
8b. Jurisdictional GCP Demand Recoverable Costs [c]	$55,094	$61,635	$210,024	$180,754	$289,287	$269,384	$165,748	$139,709	$168,405	$105,769	$176,703	$241,338	$2,063,849
9. Total Jurisdictional Recoverable Costs for O&M Activities [d]	$1,801,543	$2,530,350	$2,348,467	$2,515,814	$2,669,478	$3,246,176	$3,456,368	$3,283,451	$2,266,734	$3,296,207	$3,212,958	$3,127,332	$33,754,880

[a] Line 3 x 5
[b] Line 4a x Line 6a
[c] Line 4b x Line 6b
[d] Line 7 + Line 8a + 8b

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

REVISED FORM: 42-6A

JANUARY 2017 THROUGH DECEMBER 2017
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
Capital Projects	ECRC - 2017 Final True-Up [a]	ECRC - 2017 Actual/Estimated Filing [b]	Dif. ECRC - 2017 Actual/Estimated Filing [c]	% Dif. ECRC - 2017 Actual/Estimated Filing [d]
2 - Low NOX Burner Technology	$70,450	$70,450	$0	(0.0%)
3 - Continuous Emission Monitoring Systems	$590,622	$601,145	($10,524)	(1.8%)
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,829,586	$1,791,982	$24,806	1.4%
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,965	$1,965	$0	(0.0%)
8 - Oil Spill Clean-up/Response Equipment	$182,362	$176,138	$6,906	3.9%
10 - Relocate Storm Water Runoff	$7,496	$7,496	$0	(0.0%)
NA-Amortization of Gains on Sales of Emissions Allowances	($278)	($278)	$0	(0.0%)
12 - Scherer Discharge Pipeline	$40,814	$40,814	$0	(0.0%)
20 - Wastewater Discharge Elimination & Reuse	$88,952	$88,952	$0	(0.0%)
21 - St. Lucie Turtle Nets	$866,986	$866,986	$0	(0.0%)
22 - Pipeline Integrity Management	$313,316	$314,809	($1,493)	(0.5%)
23 - SPCC - Spill Prevention, Control & Countermeasures	$2,217,620	$2,291,013	($74,075)	(3.2%)
24 - Manatee Reburn	$3,591,326	$3,591,327	($1)	(0.0%)
26 - UST Remove/Replacement	$7,888	$7,888	$0	(0.0%)
28 - CWA 316(b) Phase II Rule	$49,632	$72,282	($22,650)	(31.3%)
31 - Clean Air Interstate Rule (CAIR) Compliance	$57,196,003	$57,230,796	($34,793)	(0.1%)
33 - MATS Project	$11,048,537	$11,048,537	$0	0.0%
34 - St Lucie Cooling Water System Inspection & Maintenance	$410,206	$408,341	$1,865	0.5%
35 - Martin Plant Drinking Water System Compliance	$23,796	$23,796	$0	(0.0%)
36 - Low-Level Radioactive Waste Storage	$1,966,477	$1,966,477	$0	(0.0%)
37 - DeSoto Next Generation Solar Energy Center	$14,988,059	$14,987,903	$157	0.0%
38 - Space Coast Next Generation Solar Energy Center	$6,960,615	$6,961,171	($556)	(0.0%)
39 - Martin Next Generation Solar Energy Center	$41,764,837	$41,784,040	($19,203)	(0.0%)
41 - Manatee Temporary Heating System	$38,309	$36,320	$1,989	5.5%
42 - Turkey Point Cooling Canal Monitoring Plan	$3,042,331	$3,538,078	($495,747)	(14.0%)
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$17,363	$17,363	$0	(0.0%)
45 - 800 MW Unit ESP	$27,680,644	$27,680,544	$100	0.0%
54 - Coal Combustion Residuals	$694,299	$937,265	($242,966)	(25.9%)
Total	$175,690,214	$176,543,602	$853,388	(0.5%)

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

REVISED FORM: 42-6A

JANUARY 2017 THROUGH DECEMBER 2017
VARIANCE REPORT OF CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)
	ECRC - 2017 Final True-Up	ECRC - 2017 Actual/Estimated Filing	Dif. ECRC - 2017 Actual/Estimated Filing	% Dif. ECRC - 2017 Actual/Estimated Filing
2. Total Investment Projects - Recoverable Costs	$175,690,214	$176,543,602	($853,388)	(0.5%)
3. Recoverable Costs Allocated to Energy	$15,305,232	$15,384,417	($80,170)	(0.5%)
4. Recoverable Costs Allocated to Demand	$160,384,983	$161,159,185	($774,202)	(0.5%)
7. Jurisdictional Energy Recoverable Costs	$14,523,398	$14,598,538	($76,074)	(0.5%)
8. Jurisdictional Demand Recoverable Costs	$152,440,441	$153,176,294	($735,853)	(0.5%)
9. Total Jurisdictional Recoverable Costs for Investment Projects	$166,963,839	$167,774,832	($811,927)	(0.5%)

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

REVISED FORM: 42-7A

JANUARY 2017 THROUGH DECEMBER 2017
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Capital Investment Projects	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Twelve Month Amount
2 - Low NOX Burner Technology	$6,006	$5,982	$5,958	$5,934	$5,910	$5,885	$5,856	$5,832	$5,808	$5,784	$5,760	$5,736	$70,450
3 - Continuous Emission Monitoring Systems	$45,773	$46,320	$47,170	$47,340	$47,202	$47,339	$48,734	$51,164	$52,825	$52,918	$51,976	$51,860	$590,622
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$151,710	$151,311	$150,882	$150,463	$150,049	$149,676	$149,582	$151,192	$154,166	$156,532	$157,085	$156,938	$1,829,586
7 - Relocate Turbine Lube Oil Underground Piping to Above Grou	$169	$168	$167	$166	$165	$164	$163	$162	$161	$160	$159	$158	$1,965
8 - Oil Spill Clean-up/Response Equipment	$15,281	$15,599	$15,690	$15,787	$15,694	$15,286	$15,027	$15,014	$14,943	$14,889	$14,819	$14,333	$182,362
10 - Relocate Storm Water Runoff	$634	$633	$631	$629	$628	$626	$623	$622	$620	$618	$617	$615	$7,496
NA-Amortization of Gains on Sales of Emissions Allowances	($37)	($35)	($32)	($30)	($28)	($25)	($22)	($19)	($17)	($14)	($11)	($8)	($278)
12 - Scherer Discharge Pipeline	$3,457	$3,447	$3,437	$3,428	$3,418	$3,408	$3,394	$3,384	$3,375	$3,365	$3,355	$3,345	$40,814
20 - Wastewater Discharge Elimination & Reuse	$7,541	$7,519	$7,496	$7,474	$7,451	$7,428	$7,397	$7,374	$7,352	$7,329	$7,307	$7,284	$88,952
21 - St. Lucie Turtle Nets	$72,853	$72,753	$72,654	$72,554	$72,455	$72,355	$72,142	$72,043	$71,943	$71,844	$71,745	$71,645	$866,986
22 - Pipeline Integrity Management	$26,397	$26,348	$26,299	$26,251	$26,202	$26,153	$26,066	$26,017	$25,969	$25,920	$25,871	$25,822	$313,316
23 - SPCC - Spill Prevention, Control & Countermeasures	$186,272	$185,889	$186,115	$185,814	$184,766	$184,484	$184,584	$184,461	$183,763	$183,332	$182,965	$185,175	$2,217,620
24 - Manatee Reburn	$304,786	$303,814	$302,842	$301,871	$300,899	$299,927	$298,623	$297,653	$296,683	$295,713	$294,743	$293,772	$3,591,326
26 - UST Remove/Replacement	$664	$663	$662	$661	$659	$658	$656	$655	$654	$653	$652	$651	$7,888
28 - CWA 316(b) Phase II Rule	$2,680	$2,743	$2,772	$2,807	$3,052	$3,316	$3,397	$3,878	$4,553	$5,799	$7,129	$7,507	$49,632
31 - Clean Air Interstate Rule (CAIR) Compliance	$4,827,639	$4,817,689	$4,807,571	$4,797,458	$4,787,294	$4,777,289	$4,760,691	$4,746,615	$4,733,471	$4,723,447	$4,713,393	$4,703,445	$57,196,003
33 - MATS Project	$931,925	$930,002	$928,081	$926,158	$924,235	$922,313	$919,101	$917,182	$915,263	$913,344	$911,426	$909,507	$11,048,537
34 - St Lucie Cooling Water System Inspection & Maintenance	$33,939	$33,969	$33,998	$34,046	$34,089	$34,140	$34,153	$34,242	$34,330	$34,400	$34,439	$34,461	$410,206
35 - Martin Plant Drinking Water System Compliance	$2,005	$2,001	$1,998	$1,994	$1,990	$1,986	$1,980	$1,976	$1,972	$1,968	$1,964	$1,961	$23,796
36 - Low-Level Radioactive Waste Storage	$165,679	$165,372	$165,065	$164,759	$164,452	$164,145	$163,600	$163,293	$162,987	$162,681	$162,375	$162,069	$1,966,477
37 - DeSoto Next Generation Solar Energy Center	$1,268,885	$1,264,922	$1,261,055	$1,257,118	$1,253,272	$1,249,551	$1,248,072	$1,244,338	$1,240,603	$1,236,852	$1,233,101	$1,230,291	$14,988,059
38 - Space Coast Next Generation Solar Energy Center	$589,137	$587,465	$585,749	$584,033	$582,142	$580,252	$579,480	$577,810	$576,141	$574,472	$572,802	$571,133	$6,960,615
39 - Martin Next Generation Solar Energy Center	$3,511,653	$3,509,697	$3,504,173	$3,496,369	$3,490,284	$3,484,643	$3,482,459	$3,472,949	$3,464,457	$3,456,022	$3,449,186	$3,442,943	$41,764,837
41 - Manatee Temporary Heating System	$2,121	$2,527	$2,115	$2,113	$2,112	$2,033	$2,022	$2,230	$2,367	$4,135	$6,081	$8,452	$38,309
42 - Turkey Point Cooling Canal Monitoring Plan	$225,721	$226,186	$230,047	$234,984	$237,754	$240,298	$244,184	$251,870	$262,188	$279,766	$298,754	$310,579	$3,042,331
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$1,463	$1,460	$1,457	$1,455	$1,452	$1,449	$1,445	$1,442	$1,439	$1,437	$1,434	$1,431	$17,363
45 - 800 MW Unit ESP	$2,342,719	$2,336,526	$2,330,211	$2,324,018	$2,317,787	$2,311,375	$2,302,171	$2,295,821	$2,289,471	$2,283,121	$2,276,772	$2,270,653	$27,680,644
54 - Coal Combustion Residuals	$28,415	$32,126	$34,343	$38,031	$42,415	$47,109	$51,576	$56,835	$63,456	$73,085	$86,383	$140,526	$694,299
Total	$14,755,485	$14,733,097	$14,708,609	$14,683,685	$14,657,799	$14,633,264	$14,607,156	$14,586,036	$14,570,943	$14,569,574	$14,572,282	$14,612,284	$175,690,214

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

JANUARY 2017 THROUGH DECEMBER 2017
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

(1)	(2)	(3)	(4)
Method of Classification	Total	CP Demand	Energy
2 - Low NOX Burner Technology	$70,450	$0	$70,450
3 - Continuous Emission Monitoring Systems	$590,622	$0	$590,622
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	$1,829,586	$1,688,849	$140,737
7 - Relocate Turbine Lube Oil Underground Piping to Above Ground	$1,965	$1,814	$151
8 - Oil Spill Clean-up/Response Equipment	$182,362	$168,334	$14,028
10 - Relocate Storm Water Runoff	$7,496	$6,920	$577
NA-Amortization of Gains on Sales of Emissions Allowances	($278)	$0	($278)
12 - Scherer Discharge Pipeline	$40,814	$37,675	$3,140
20 - Wastewater Discharge Elimination & Reuse	$88,952	$82,110	$6,842
21 - St. Lucie Turtle Nets	$866,986	$800,295	$66,691
22 - Pipeline Integrity Management	$313,316	$289,215	$24,101
23 - SPCC - Spill Prevention, Control & Countermeasures	$2,217,620	$2,047,034	$170,586
24 - Manatee Reburn	$3,591,326	$0	$3,591,326
25 - Pt. Everglades ESP Technology	$0	$0	$0
26 - UST Remove/Replacement	$7,888	$7,281	$607
28 - CWA 316(b) Phase II Rule	$49,632	$49,632	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	$57,196,003	$52,796,310	$4,399,693
33 - MATS Project	$11,048,537	$10,198,649	$849,887
34 - St Lucie Cooling Water System Inspection & Maintenance	$410,206	$378,652	$31,554
35 - Martin Plant Drinking Water System Compliance	$23,796	$21,965	$1,830
36 - Low-Level Radioactive Waste Storage	$1,966,477	$1,815,209	$151,267
37 - DeSoto Next Generation Solar Energy Center	$14,988,059	$13,835,132	$1,152,928
38 - Space Coast Next Generation Solar Energy Center	$6,960,615	$6,425,183	$535,432
39 - Martin Next Generation Solar Energy Center	$41,764,837	$38,552,157	$3,212,680
41 - Manatee Temporary Heating System	$38,309	$35,362	$2,947
42 - Turkey Point Cooling Canal Monitoring Plan	$3,042,331	$2,808,306	$234,025
44 - Martin Plant Barley Barber Swamp Iron Mitigation	$17,363	$17,363	$0
45 - 800 MW Unit ESP	$27,680,644	$27,680,644	$0
54 - Coal Combustion Residuals	$694,299	$640,891	$53,408
Total	$175,690,214	$160,384,983	$15,305,232

Each project's Total System 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

JANUARY 2017 THROUGH DECEMBER 2017
CAPITAL INVESTMENT PROJECTS-RECOVERABLE COSTS

	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Twelve Month Amount
2. Total Investment Projects - Recoverable Costs	$14,755,485	$14,733,097	$14,708,609	$14,683,685	$14,657,799	$14,633,264	$14,607,156	$14,586,036	$14,570,943	$14,569,574	$14,572,282	$14,612,284	$175,690,214
3. Recoverable Costs Allocated to Energy	$1,283,612	$1,281,949	$1,280,417	$1,278,214	$1,275,638	$1,273,434	$1,272,188	$1,272,342	$1,272,236	$1,271,695	$1,270,505	$1,273,001	$15,305,232
4. Recoverable Costs Allocated to Demand	$13,471,873	$13,451,148	$13,428,191	$13,405,471	$13,382,161	$13,359,830	$13,334,968	$13,313,694	$13,298,707	$13,297,879	$13,301,777	$13,339,284	$160,384,983
5.Retail Energy Jurisdictional Factor	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	
6. Retail Demand Jurisdictional Factor	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	
7. Jurisdictional Energy Recoverable Costs [a]	$1,218,042	$1,216,464	$1,215,010	$1,212,919	$1,210,475	$1,208,384	$1,207,201	$1,207,348	$1,207,247	$1,206,734	$1,205,604	$1,207,972	$14,523,398
8. Jurisdictional Demand Recoverable Costs [b]	$12,804,555	$12,784,856	$12,763,037	$12,741,441	$12,719,286	$12,698,062	$12,674,431	$12,654,211	$12,639,966	$12,639,179	$12,642,884	$12,678,533	$152,440,441
9. Total Jurisdictional Recoverable Costs for Investment Projects	$14,022,596	$14,001,320	$13,978,047	$13,954,361	$13,929,761	$13,906,445	$13,881,632	$13,861,558	$13,847,213	$13,845,913	$13,848,488	$13,886,505	$166,963,839

[a] Line 3 x Line 5
[b] Line 4 x Line 6

FLORIDA POWER & LIGHT COMPANY
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02 - Low NOX Burner Technology	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$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	
3a. Less: Accumulated Depreciation	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
3b. Less: Capital Recovery Unamortized Balance	($375,828)	($372,696)	($369,564)	($366,432)	($363,300)	($360,168)	($357,036)	($353,904)	($350,772)	($347,640)	($344,509)	($341,377)	($338,245)	
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$375,828	$372,696	$369,564	$366,432	$363,300	$360,168	$357,036	$353,905	$350,773	$347,641	$344,509	$341,377	$338,245	
6. Average Net Investment		$374,262	$371,130	$367,998	$364,866	$361,734	$358,602	$355,471	$352,339	$349,207	$346,075	$342,943	$339,811	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,438	$2,417	$2,397	$2,376	$2,356	$2,336	$2,327	$2,306	$2,286	$2,265	$2,245	$2,224	$27,974
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$436	$432	$429	$425	$422	$418	$397	$394	$390	$387	$383	$380	$4,894
8. Investment Expenses														
a. Depreciation [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization [e]		$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$37,583
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$6,006	$5,982	$5,958	$5,934	$5,910	$5,885	$5,856	$5,832	$5,808	$5,784	$5,760	$5,736	$70,450

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon
Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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03 - Continuous Emission Monitoring Systems	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$187,673	$79,766	$13,487	$947	$84,080	($68,641)	($122,280)	$136,306	($16,709)	($225,388)	($113,075)	($43,835)
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$255,503	$329,123	$1,591	($269,211)	($350,989)	$165,992	$132,009
c. Retirements	$0	$0	$0	$0	$0	$0	$0	($36,022)	($5,722)	$0	($362,458)	($620,363)	($16,367)	($1,040,932)
d. Other	$0	$0	($4,056)	($1,720)	($290)	($21)	($1,764)	($4,852)	($4,759)	($2,866)	($1,546)	($883)	($1,542)	($24,300)
2. Plant-In Service/Depreciation Base [a]	$5,690,778	$5,690,778	$5,690,778	$5,690,778	$5,690,778	$5,690,778	$5,690,778	$5,946,280	$6,275,404	$6,276,995	$6,007,784	$5,656,795	$5,822,787	
3a. Less: Accumulated Depreciation	$3,576,307	$3,597,587	$3,614,817	$3,634,380	$3,655,372	$3,676,635	$3,696,154	$3,676,996	$3,689,156	$3,709,428	$3,368,023	$2,768,164	$2,771,277	
3b. Less: Capital Recovery Unamortized Balance	($500,741)	($496,568)	($492,395)	($488,222)	($484,050)	($479,877)	($475,704)	($471,531)	($467,358)	($463,185)	($459,013)	($454,840)	($450,667)	
4. CWIP - Non Interest Bearing	$43,835	$43,835	$231,508	$311,274	$324,761	$325,708	$409,788	$341,147	$218,867	$355,173	$338,463	$113,075	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,659,047	$2,633,594	$2,799,864	$2,855,894	$2,844,215	$2,819,728	$2,880,115	$3,081,962	$3,272,472	$3,385,925	$3,437,237	$3,456,545	$3,502,177	
6. Average Net Investment		$2,646,320	$2,716,729	$2,827,879	$2,850,055	$2,831,972	$2,849,921	$2,981,039	$3,177,217	$3,329,199	$3,411,581	$3,446,891	$3,479,361	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$17,236	$17,695	$18,419	$18,563	$18,446	$18,562	$19,514	$20,798	$21,793	$22,332	$22,563	$22,776	$238,698
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$3,084	$3,166	$3,295	$3,321	$3,300	$3,321	$3,332	$3,551	$3,721	$3,813	$3,853	$3,889	$41,648
8. Investment Expenses														
a. Depreciation [d]		$21,280	$21,286	$21,283	$21,283	$21,283	$21,283	$21,715	$22,641	$23,137	$22,600	$21,387	$21,022	$260,201
b. Amortization [e]		$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$4,173	$50,074
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$45,773	$46,320	$47,170	$47,340	$47,202	$47,339	$48,734	$51,164	$52,825	$52,918	$51,976	$51,860	$590,622

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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05 - Maintenance of Stationary Above Ground Storage Tanks	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$1,103	$10,844	$121,616	$237,522	$477,768	$249,308	$4,662	$64,230	$1,167,053
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$133,572	$0	$0	$0	$0	$133,572
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($23)	($28)	$0	($51)
2. Plant-In Service/Depreciation Base [a]	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,393,764	$13,527,336	$13,527,336	$13,527,336	$13,527,336	$13,527,336	
3a. Less: Accumulated Depreciation	$3,867,188	$3,895,415	$3,923,662	$3,951,900	$3,980,137	$4,008,412	$4,036,657	$4,064,901	$4,093,286	$4,121,812	$4,150,314	$4,178,811	$4,207,346	
3b. Less: Capital Recovery Unamortized Balance	($3,156,456)	($3,130,152)	($3,103,849)	($3,077,545)	($3,051,241)	($3,024,975)	($2,998,678)	($2,972,382)	($2,946,086)	($2,919,789)	($2,893,493)	($2,867,197)	($2,840,901)	
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$1,103	$11,947	$133,563	$371,085	$848,854	$1,098,161	$1,102,823	$1,167,053	
5. Net Investment (Lines 2 - 3 + 4)	$12,683,032	$12,628,501	$12,573,950	$12,519,409	$12,464,868	$12,411,430	$12,367,733	$12,434,808	$12,751,220	$13,174,167	$13,368,676	$13,318,544	$13,327,944	
6. Average Net Investment		$12,655,766	$12,601,225	$12,546,679	$12,492,138	$12,438,149	$12,389,581	$12,401,270	$12,593,014	$12,962,694	$13,271,421	$13,343,610	$13,323,244	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$82,431	$82,076	$81,720	$81,365	$81,014	$80,697	$81,179	$82,434	$84,854	$86,875	$87,348	$87,214	$999,208
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$14,748	$14,684	$14,621	$14,557	$14,494	$14,438	$13,862	$14,076	$14,490	$14,835	$14,915	$14,893	$174,613
8. Investment Expenses														
a. Depreciation [d]		$28,228	$28,247	$28,237	$28,237	$28,245	$28,245	$28,245	$28,385	$28,525	$28,525	$28,525	$28,535	$340,210
b. Amortization [e]		$26,304	$26,304	$26,304	$26,304	$26,296	$26,296	$26,296	$26,296	$26,296	$26,296	$26,296	$26,296	$315,556
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$151,710	$151,311	$150,882	$150,463	$150,049	$149,676	$149,582	$151,192	$154,166	$156,532	$157,085	$156,938	$1,829,586

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$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	$26,112	$26,244	$26,376	$26,508	$26,640	$26,772	$26,905	$27,037	$27,169	$27,301	$27,433	$27,565	$27,697	
3b. Less: Capital Recovery Unamortized Balance	$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)	$4,918	$4,786	$4,654	$4,522	$4,390	$4,258	$4,125	$3,993	$3,861	$3,729	$3,597	$3,465	$3,333	
6. Average Net Investment		$4,852	$4,720	$4,588	$4,456	$4,324	$4,191	$4,059	$3,927	$3,795	$3,663	$3,531	$3,399	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$32	$31	$30	$29	$28	$27	$27	$26	$25	$24	$23	$22	$323
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$6	$6	$5	$5	$5	$5	$5	$4	$4	$4	$4	$4	$57
8. Investment Expenses														
a. Depreciation [d]		$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$1,586
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$169	$168	$167	$166	$165	$164	$163	$162	$161	$160	$159	$158	$1,965

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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

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08 - Oil Spill Clean-up/Response Equipment	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	Total
1. Investments														
a. Expenditures/Additions	$0	$1,051	$16,400	$20,858	$11,495	$2,831	($13,432)	$0	$0	$0	$181	$0	($178,014)	($138,631)
b. Clearings to Plant	$0	$2,154	$0	$2,638	$2,518	$0	($36,031)	$5,984	($1,254)	$0	$0	($2,743)	$14,850	($11,883)
c. Retirements	$0	$2,154	$0	($5,007)	$0	$0	($40,930)	$0	($1,254)	$0	$0	($2,743)	($31,522)	($79,302)
d. Other	$0	$0	$0	$0	$0	$30,000	$0	$0	$0	$0	$0	$0	$0	$30,000
2. Plant-In Service/Depreciation Base [a]	$949,127	$951,281	$951,281	$953,919	$956,438	$956,438	$920,407	$926,391	$925,137	$925,137	$925,137	$922,395	$937,244	
3a. Less: Accumulated Depreciation	$28,051	$37,376	$44,854	$47,300	$54,745	$92,205	$58,520	$65,586	$71,417	$78,484	$85,551	$89,859	$65,459	
3b. Less: Capital Recovery Unamortized Balance	$220	$218	$216	$214	$212	$211	$209	$207	$205	$203	$201	$200	$198	
4. CWIP - Non Interest Bearing	$138,662	$139,713	$156,113	$176,971	$188,465	$191,296	$177,864	$177,864	$177,864	$177,864	$178,045	$178,045	$31	
5. Net Investment (Lines 2 - 3 + 4)	$1,059,518	$1,053,401	$1,062,325	$1,083,375	$1,089,946	$1,055,318	$1,039,542	$1,038,462	$1,031,379	$1,024,314	$1,017,430	$1,010,381	$871,618	
6. Average Net Investment		$1,056,459	$1,057,863	$1,072,850	$1,086,661	$1,072,632	$1,047,430	$1,039,002	$1,034,921	$1,027,847	$1,020,872	$1,013,905	$940,999	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$6,881	$6,890	$6,988	$7,078	$6,986	$6,822	$6,801	$6,775	$6,728	$6,683	$6,637	$6,160	$81,429
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$1,231	$1,233	$1,250	$1,266	$1,250	$1,221	$1,161	$1,157	$1,149	$1,141	$1,133	$1,052	$14,244
8. Investment Expenses														
a. Depreciation [d]		$7,170	$7,478	$7,454	$7,445	$7,460	$7,245	$7,066	$7,085	$7,067	$7,067	$7,051	$7,123	$86,710
b. Amortization [e]		($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($22)
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$15,281	$15,599	$15,690	$15,787	$15,694	$15,286	$15,027	$15,014	$14,943	$14,889	$14,819	$14,333	$182,362

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

FLORIDA POWER & LIGHT COMPANY
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10 - Relocate Storm Water Runoff	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	$117,794	
3a. Less: Accumulated Depreciation	$63,827	$64,048	$64,269	$64,490	$64,711	$64,932	$65,152	$65,373	$65,594	$65,815	$66,036	$66,257	$66,478	
3b. Less: Capital Recovery Unamortized Balance	$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)	$53,967	$53,746	$53,525	$53,304	$53,083	$52,862	$52,641	$52,421	$52,200	$51,979	$51,758	$51,537	$51,316	
6. Average Net Investment		$53,856	$53,635	$53,414	$53,194	$52,973	$52,752	$52,531	$52,310	$52,089	$51,868	$51,648	$51,427	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$351	$349	$348	$346	$345	$344	$344	$342	$341	$340	$338	$337	$4,125
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$63	$63	$62	$62	$62	$61	$59	$58	$58	$58	$58	$57	$721
8. Investment Expenses														
a. Depreciation [d]		$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$2,650
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$634	$633	$631	$629	$628	$626	$623	$622	$620	$618	$617	$615	$7,496

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

FLORIDA POWER & LIGHT COMPANY
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12 - Scherer Discharge Pipeline	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$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	$569,216	$570,488	$571,761	$573,033	$574,306	$575,579	$576,851	$578,124	$579,396	$580,669	$581,942	$583,214	$584,487	
3b. Less: Capital Recovery Unamortized Balance	$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)	$285,108	$283,835	$282,563	$281,290	$280,018	$278,745	$277,472	$276,200	$274,927	$273,655	$272,382	$271,109	$269,837	
6. Average Net Investment		$284,472	$283,199	$281,927	$280,654	$279,381	$278,109	$276,836	$275,564	$274,291	$273,018	$271,746	$270,473	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,853	$1,845	$1,836	$1,828	$1,820	$1,811	$1,812	$1,804	$1,796	$1,787	$1,779	$1,771	$21,741
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$331	$330	$329	$327	$326	$324	$309	$308	$307	$305	$304	$302	$3,802
8. Investment Expenses														
a. Depreciation [d]		$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$15,271
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$3,457	$3,447	$3,437	$3,428	$3,418	$3,408	$3,394	$3,384	$3,375	$3,365	$3,355	$3,345	$40,814

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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20 - Wastewater Discharge Elimination & Reuse	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	
3a. Less: Accumulated Depreciation	$172,106	$175,056	$178,005	$180,955	$183,905	$186,855	$189,804	$192,754	$195,704	$198,653	$201,603	$204,553	$207,503	
3b. Less: Capital Recovery Unamortized Balance	$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)	$599,471	$596,521	$593,571	$590,622	$587,672	$584,722	$581,772	$578,823	$575,873	$572,923	$569,974	$567,024	$564,074	
6. Average Net Investment		$597,996	$595,046	$592,096	$589,147	$586,197	$583,247	$580,298	$577,348	$574,398	$571,448	$568,499	$565,549	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$3,895	$3,876	$3,857	$3,837	$3,818	$3,799	$3,799	$3,779	$3,760	$3,741	$3,721	$3,702	$45,584
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$697	$693	$690	$687	$683	$680	$649	$645	$642	$639	$635	$632	$7,972
8. Investment Expenses														
a. Depreciation [d]		$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$35,397
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$7,541	$7,519	$7,496	$7,474	$7,451	$7,428	$7,397	$7,374	$7,352	$7,329	$7,307	$7,284	$88,952

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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21 - St. Lucie Turtle Nets	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	$6,909,559	
3a. Less: Accumulated Depreciation	($897,472)	($884,516)	($871,561)	($858,605)	($845,650)	($832,695)	($819,739)	($806,784)	($793,828)	($780,873)	($767,917)	($754,962)	($742,007)	
3b. Less: Capital Recovery Unamortized Balance	$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)	$7,807,030	$7,794,075	$7,781,119	$7,768,164	$7,755,209	$7,742,253	$7,729,298	$7,716,342	$7,703,387	$7,690,431	$7,677,476	$7,664,521	$7,651,565	
6. Average Net Investment		$7,800,553	$7,787,597	$7,774,642	$7,761,686	$7,748,731	$7,735,775	$7,722,820	$7,709,865	$7,696,909	$7,683,954	$7,670,998	$7,658,043	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$50,807	$50,723	$50,639	$50,554	$50,470	$50,385	$50,554	$50,469	$50,384	$50,299	$50,215	$50,130	$605,630
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$9,090	$9,075	$9,060	$9,045	$9,030	$9,014	$8,633	$8,618	$8,604	$8,589	$8,575	$8,560	$105,892
8. Investment Expenses														
a. Depreciation [d]		$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$155,465
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$72,853	$72,753	$72,654	$72,554	$72,455	$72,355	$72,142	$72,043	$71,943	$71,844	$71,745	$71,645	$866,986

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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

FORM: 42-8A

JANUARY 2017 THROUGH DECEMBER 2017

22 - Pipeline Integrity Management	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	$2,872,791	
3a. Less: Accumulated Depreciation	$259,949	$266,307	$272,666	$279,024	$285,383	$291,741	$298,100	$304,458	$310,817	$317,175	$323,534	$329,892	$336,251	
3b. Less: Capital Recovery Unamortized Balance														
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,612,843	$2,606,484	$2,600,126	$2,593,767	$2,587,409	$2,581,050	$2,574,692	$2,568,333	$2,561,975	$2,555,616	$2,549,258	$2,542,899	$2,536,541	
6. Average Net Investment		$2,609,663	$2,603,305	$2,596,946	$2,590,588	$2,584,229	$2,577,871	$2,571,512	$2,565,154	$2,558,795	$2,552,437	$2,546,078	$2,539,720	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$16,998	$16,956	$16,915	$16,873	$16,832	$16,790	$16,833	$16,792	$16,750	$16,708	$16,667	$16,625	$201,739
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$3,041	$3,034	$3,026	$3,019	$3,011	$3,004	$2,874	$2,867	$2,860	$2,853	$2,846	$2,839	$35,275
8. Investment Expenses														
a. Depreciation [d]		$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$6,359	$76,302
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$26,397	$26,348	$26,299	$26,251	$26,202	$26,153	$26,066	$26,017	$25,969	$25,920	$25,871	$25,822	$313,316

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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

REVISED FORM: 42-8A

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23 - SPCC - Spill Prevention, Control & Countermeasures	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	Total
1. Investments														
a. Expenditures/Additions	$0	($10,937)	($283)	$24,217	$21,865	$3,863	$8,284	$56,394	$12,423	$7,464	($9,112)	($90,467)	$673,266	$696,977
b. Clearings to Plant	$0	$31,839	($1,695)	$140,969	($137,186)	($5,129)	$37,285	$84,938	($60,871)	$0	$8,744	$96,265	$6,323	$201,482
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($8,126)	$0	$0	($8,126)
d. Other	$0	($418)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($418)
2. Plant-In Service/Depreciation Base [a]	$16,329,193	$16,361,032	$16,359,337	$16,500,306	$16,363,119	$16,357,991	$16,395,276	$16,480,214	$16,419,343	$16,419,343	$16,428,087	$16,524,352	$16,530,675	
3a. Less: Accumulated Depreciation	$3,325,715	$3,366,273	$3,407,289	$3,448,401	$3,489,518	$3,530,531	$3,571,589	$3,612,758	$3,653,944	$3,695,086	$3,728,110	$3,769,338	$3,810,646	
3b. Less: Capital Recovery Unamortized Balance	($2,837,506)	($2,813,860)	($2,790,214)	($2,766,568)	($2,742,922)	($2,719,276)	($2,695,630)	($2,671,984)	($2,648,339)	($2,624,693)	($2,601,047)	($2,577,401)	($2,553,755)	
4. CWIP - Non Interest Bearing	$23,310	$12,373	$12,090	$36,307	$58,172	$62,035	$70,319	$126,713	$139,136	$146,600	$137,488	$47,020	$720,287	
5. Net Investment (Lines 2 - 3 + 4)	$15,864,294	$15,820,992	$15,754,352	$15,854,780	$15,674,695	$15,608,771	$15,589,636	$15,666,153	$15,552,873	$15,495,550	$15,438,511	$15,379,436	$15,994,071	
6. Average Net Investment		$15,842,643	$15,787,672	$15,804,566	$15,764,738	$15,641,733	$15,599,203	$15,627,894	$15,609,513	$15,524,211	$15,467,030	$15,408,973	$15,686,753	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$103,188	$102,830	$102,940	$102,681	$101,879	$101,602	$102,301	$102,180	$101,622	$101,248	$100,868	$102,686	$1,226,025
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$18,461	$18,397	$18,417	$18,371	$18,227	$18,178	$17,469	$17,448	$17,353	$17,289	$17,224	$17,535	$214,370
8. Investment Expenses														
a. Depreciation [d]		$40,976	$41,016	$41,112	$41,117	$41,013	$41,058	$41,169	$41,186	$41,142	$41,150	$41,228	$41,308	$493,475
b. Amortization [e]		$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$23,646	$283,751
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$186,272	$185,889	$186,115	$185,814	$184,766	$184,484	$184,584	$184,461	$183,763	$183,332	$182,965	$185,175	$2,217,620

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

FLORIDA POWER & LIGHT COMPANY
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24 - Manatee Reburn	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	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	($122)	($122)
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17	$17
2. Plant-In Service/Depreciation Base [a]	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,858	$31,581,736	
3a. Less: Accumulated Depreciation	$8,384,671	$8,511,243	$8,637,815	$8,764,388	$8,890,960	$9,017,532	$9,144,104	$9,270,677	$9,397,249	$9,523,821	$9,650,394	$9,776,966	$9,903,555	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	$75,239	
5. Net Investment (Lines 2 - 3 + 4)	$23,272,426	$23,145,854	$23,019,282	$22,892,709	$22,766,137	$22,639,565	$22,512,992	$22,386,420	$22,259,848	$22,133,275	$22,006,703	$21,880,131	$21,753,420	
6. Average Net Investment		$23,209,140	$23,082,568	$22,955,995	$22,829,423	$22,702,851	$22,576,279	$22,449,706	$22,323,134	$22,196,562	$22,069,989	$21,943,417	$21,816,775	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$151,168	$150,344	$149,519	$148,695	$147,871	$147,046	$146,956	$146,128	$145,299	$144,471	$143,642	$142,813	$1,763,954
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$27,046	$26,898	$26,751	$26,603	$26,456	$26,308	$25,094	$24,953	$24,811	$24,670	$24,528	$24,387	$308,505
8. Investment Expenses														
a. Depreciation [d]		$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$126,572	$1,518,867
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$304,786	$303,814	$302,842	$301,871	$300,899	$299,927	$298,623	$297,653	$296,683	$295,713	$294,743	$293,772	$3,591,326

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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25 - Pt. Everglades ESP Technology	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$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	
3a. Less: Accumulated Depreciation	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	
3b. Less: Capital Recovery Unamortized Balance	$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)	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	
6. Average Net Investment		$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. Investment Expenses														
a. Depreciation [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$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 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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26 - UST Remove/Replacement	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	$115,447	
3a. Less: Accumulated Depreciation	$47,708	$47,852	$47,996	$48,141	$48,285	$48,429	$48,574	$48,718	$48,862	$49,007	$49,151	$49,295	$49,440	
3b. Less: Capital Recovery Unamortized Balance	$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)	$67,739	$67,595	$67,450	$67,306	$67,162	$67,017	$66,873	$66,729	$66,584	$66,440	$66,296	$66,151	$66,007	
6. Average Net Investment		$67,667	$67,522	$67,378	$67,234	$67,089	$66,945	$66,801	$66,657	$66,512	$66,368	$66,224	$66,079	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$441	$440	$439	$438	$437	$436	$437	$436	$435	$434	$434	$433	$5,240
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$79	$79	$79	$78	$78	$78	$75	$75	$74	$74	$74	$74	$916
8. Investment Expenses														
a. Depreciation [d]		$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,732
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$664	$663	$662	$661	$659	$658	$656	$655	$654	$653	$652	$651	$7,888

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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28 - CWA 316(b) Phase II Rule	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	Total
1. Investments														
a. Expenditures/Additions	$0	$10,876	$5,482	$2,172	$6,895	$56,979	$11,817	$10,833	$114,691	$61,674	($624,986)	$0	$0	($343,567)
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$687,829	$66,242	$12,574	$766,645
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$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	$687,829	$754,071	$766,645	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$771	$2,387	$4,092	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$343,567	$354,443	$359,925	$362,097	$368,992	$425,971	$437,788	$448,621	$563,312	$624,986	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$343,567	$354,443	$359,925	$362,097	$368,992	$425,971	$437,788	$448,621	$563,312	$624,986	$687,058	$751,684	$762,553	
6. Average Net Investment		$349,005	$357,184	$361,011	$365,544	$397,481	$431,880	$443,205	$505,967	$594,149	$656,022	$719,371	$757,118	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,273	$2,326	$2,351	$2,381	$2,589	$2,813	$2,901	$3,312	$3,889	$4,294	$4,709	$4,956	$38,796
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$407	$416	$421	$426	$463	$503	$495	$566	$664	$733	$804	$846	$6,745
8. Investment Expenses														
a. Depreciation [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$771	$1,616	$1,704	$4,092
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,680	$2,743	$2,772	$2,807	$3,052	$3,316	$3,397	$3,878	$4,553	$5,799	$7,129	$7,507	$49,632

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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31 - Clean Air Interstate Rule (CAIR) Compliance	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	Total
1. Investments														
a. Expenditures/Additions	$0	$41,015	$992	($41,537)	$2,110	$737	$43,258	$171	$7,653	$9,026	$3,645	$1,202	($68,703)	($430)
b. Clearings to Plant	$0	$3,833	$0	$1,756	$11	($24,030)	$0	$0	($2,494,657)	$0	$0	$0	$79,730	($2,433,357)
c. Retirements	$0	$0	$0	($41,546)	$0	($24,395)	$0	$0	($2,084,194)	$0	$0	$0	$0	($2,150,135)
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	($107,815)	$0	$0	$0	$0	($107,815)
2. Plant-In Service/Depreciation Base [a]	$527,147,489	$527,151,322	$527,151,322	$527,153,078	$527,153,089	$527,129,059	$527,129,059	$527,129,059	$524,634,402	$524,634,402	$524,634,402	$524,634,402	$524,714,132	
3a. Less: Accumulated Depreciation	$69,676,106	$70,994,656	$72,313,209	$73,590,218	$74,908,775	$76,202,889	$77,521,352	$78,839,815	$77,963,421	$79,277,069	$80,590,716	$81,904,364	$83,218,088	
3b. Less: Capital Recovery Unamortized Balance	($77,096)	($76,454)	($75,811)	($75,169)	($74,526)	($73,884)	($73,241)	($72,599)	($71,956)	($71,314)	($70,671)	($70,029)	($69,386)	
4. CWIP - Non Interest Bearing	$430	$41,446	$42,438	$901	$3,011	$3,748	$47,007	$47,177	$54,830	$63,857	$67,502	$68,703	$0	
5. Net Investment (Lines 2 - 3 + 4)	$457,548,909	$456,274,566	$454,956,362	$453,638,929	$452,321,851	$451,003,802	$449,727,954	$448,409,020	$446,797,767	$445,492,504	$444,181,859	$442,868,770	$441,565,430	
6. Average Net Investment		$456,911,738	$455,615,464	$454,297,646	$452,980,390	$451,662,826	$450,365,878	$449,068,487	$447,603,394	$446,145,136	$444,837,181	$443,525,315	$442,217,100	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,976,007	$2,967,564	$2,958,981	$2,950,401	$2,941,820	$2,933,372	$2,939,617	$2,930,026	$2,920,480	$2,911,918	$2,903,331	$2,894,767	$35,228,284
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$532,439	$530,929	$529,393	$527,858	$526,323	$524,811	$501,969	$500,331	$498,701	$497,239	$495,773	$494,310	$6,160,076
8. Investment Expenses														
a. Depreciation [d]		$1,318,550	$1,318,553	$1,318,555	$1,318,557	$1,318,510	$1,318,463	$1,318,463	$1,315,616	$1,313,648	$1,313,648	$1,313,648	$1,313,725	$15,799,933
b. Amortization [e]		$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$642	$7,710
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$4,827,639	$4,817,689	$4,807,571	$4,797,458	$4,787,294	$4,777,289	$4,760,691	$4,746,615	$4,733,471	$4,723,447	$4,713,393	$4,703,445	$57,196,003

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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33 - MATS Project	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$250	($246)	$0	($4)	$21	$0	$0	($27)	$0	$6	$0
b. Clearings to Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($6)
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,938	$107,495,932	
3a. Less: Accumulated Depreciation	$18,609,993	$18,860,358	$19,110,724	$19,361,089	$19,611,455	$19,861,821	$20,112,186	$20,362,552	$20,612,918	$20,863,283	$21,113,649	$21,364,014	$21,614,380	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$0	$0	$0	$250	$4	$4	$0	$21	$21	$21	($6)	($6)	$0	
5. Net Investment (Lines 2 - 3 + 4)	$88,885,946	$88,635,580	$88,385,214	$88,135,099	$87,884,487	$87,634,122	$87,383,752	$87,133,407	$86,883,042	$86,632,676	$86,382,283	$86,131,918	$85,881,552	
6. Average Net Investment		$88,760,763	$88,510,397	$88,260,157	$88,009,793	$87,759,305	$87,508,937	$87,258,580	$87,008,224	$86,757,859	$86,507,480	$86,257,101	$86,006,735	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$578,126	$576,496	$574,866	$573,235	$571,603	$569,973	$571,197	$569,559	$567,920	$566,281	$564,642	$563,003	$6,846,900
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$103,433	$103,141	$102,850	$102,558	$102,266	$101,974	$97,538	$97,258	$96,978	$96,698	$96,418	$96,138	$1,197,249
8. Investment Expenses														
a. Depreciation [d]		$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$250,366	$3,004,388
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$931,925	$930,002	$928,081	$926,158	$924,235	$922,313	$919,101	$917,182	$915,263	$913,344	$911,426	$909,507	$11,048,537

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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34 - St Lucie Cooling Water System Inspection & Maintenance	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	Total
1. Investments														
a. Expenditures/Additions	$0	$4,343	$3,590	$4,035	$8,404	$2,695	$10,582	$10,139	$12,877	$10,210	$8,119	$1,942	$3,850	$80,786
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	$0	$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	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$4,417,723	$4,422,066	$4,425,656	$4,429,691	$4,438,095	$4,440,790	$4,451,372	$4,461,511	$4,474,388	$4,484,598	$4,492,717	$4,494,659	$4,498,509	
5. Net Investment (Lines 2 - 3 + 4)	$4,417,723	$4,422,066	$4,425,656	$4,429,691	$4,438,095	$4,440,790	$4,451,372	$4,461,511	$4,474,388	$4,484,598	$4,492,717	$4,494,659	$4,498,509	
6. Average Net Investment		$4,419,894	$4,423,861	$4,427,674	$4,433,893	$4,439,443	$4,446,081	$4,456,442	$4,467,950	$4,479,493	$4,488,658	$4,493,688	$4,496,584	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$28,788	$28,814	$28,839	$28,879	$28,915	$28,959	$29,172	$29,247	$29,323	$29,383	$29,416	$29,435	$349,170
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$5,151	$5,155	$5,160	$5,167	$5,173	$5,181	$4,981	$4,994	$5,007	$5,017	$5,023	$5,026	$61,036
8. Investment Expenses														
a. Depreciation [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$33,939	$33,969	$33,998	$34,046	$34,089	$34,140	$34,153	$34,242	$34,330	$34,400	$34,439	$34,461	$410,206

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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35 - Martin Plant Drinking Water System Compliance	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	$235,391	
3a. Less: Accumulated Depreciation	$38,370	$38,864	$39,359	$39,853	$40,347	$40,842	$41,336	$41,830	$42,325	$42,819	$43,313	$43,808	$44,302	
3b. Less: Capital Recovery Unamortized Balance	$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)	$197,021	$196,527	$196,033	$195,538	$195,044	$194,550	$194,055	$193,561	$193,067	$192,572	$192,078	$191,584	$191,090	
6. Average Net Investment		$196,774	$196,280	$195,786	$195,291	$194,797	$194,303	$193,808	$193,314	$192,820	$192,325	$191,831	$191,337	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,282	$1,278	$1,275	$1,272	$1,269	$1,266	$1,269	$1,265	$1,262	$1,259	$1,256	$1,252	$15,205
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$229	$229	$228	$228	$227	$226	$217	$216	$216	$215	$214	$214	$2,659
8. Investment Expenses														
a. Depreciation [d]		$494	$494	$494	$494	$494	$494	$494	$494	$494	$494	$494	$494	$5,932
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,005	$2,001	$1,998	$1,994	$1,990	$1,986	$1,980	$1,976	$1,972	$1,968	$1,964	$1,961	$23,796

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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36 - Low-Level Radioactive Waste Storage	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	$17,456,804	
3a. Less: Accumulated Depreciation	$1,064,031	$1,103,990	$1,143,948	$1,183,907	$1,223,866	$1,263,825	$1,303,784	$1,343,742	$1,383,701	$1,423,660	$1,463,619	$1,503,578	$1,543,536	
3b. Less: Capital Recovery Unamortized Balance	$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)	$16,392,773	$16,352,814	$16,312,855	$16,272,896	$16,232,938	$16,192,979	$16,153,020	$16,113,061	$16,073,102	$16,033,144	$15,993,185	$15,953,226	$15,913,267	
6. Average Net Investment		$16,372,793	$16,332,835	$16,292,876	$16,252,917	$16,212,958	$16,172,999	$16,133,041	$16,093,082	$16,053,123	$16,013,164	$15,973,205	$15,933,247	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$106,641	$106,381	$106,121	$105,860	$105,600	$105,340	$105,607	$105,346	$105,084	$104,823	$104,561	$104,300	$1,265,663
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$19,079	$19,033	$18,986	$18,940	$18,893	$18,846	$18,034	$17,989	$17,944	$17,900	$17,855	$17,810	$221,308
8. Investment Expenses														
a. Depreciation [d]		$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$479,506
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$165,679	$165,372	$165,065	$164,759	$164,452	$164,145	$163,600	$163,293	$162,987	$162,681	$162,375	$162,069	$1,966,477

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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37 - DeSoto Next Generation Solar Energy Center	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
b. Clearings to Plant	$0	($47,662)	$0	($46,992)	($21,121)	$0	$0	$0	($1,052)	$0	($4,256)	$0	$86,055	($35,027)
c. Retirements	$0	($49,116)	$0	$0	($21,238)	$0	$0	$0	$0	$0	$0	$0	($9,201)	($79,555)
d. Other	$0	($0)	($1,677)	($5,600)	$0	$0	$0	$0	$0	$0	$0	$0	($813)	($8,091)
2. Plant-In Service/Depreciation Base [a]	$153,566,725	$153,519,064	$153,519,064	$153,472,071	$153,450,951	$153,450,951	$153,450,951	$153,450,951	$153,449,899	$153,449,899	$153,445,642	$153,445,642	$153,531,698	
3a. Less: Accumulated Depreciation	$36,158,682	$36,554,171	$36,996,847	$37,435,608	$37,858,675	$38,302,854	$38,747,034	$39,191,214	$39,635,392	$40,079,569	$40,523,740	$40,967,905	$41,402,609	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
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)	$117,408,043	$116,964,892	$116,522,217	$116,036,464	$115,592,277	$115,148,097	$114,703,917	$114,259,737	$113,814,507	$113,370,330	$112,921,903	$112,477,738	$112,129,090	
6. Average Net Investment		$117,186,468	$116,743,555	$116,279,340	$115,814,370	$115,370,187	$114,926,007	$114,481,827	$114,037,122	$113,592,419	$113,146,117	$112,699,821	$112,303,414	
a. Average ITC Balance		$33,385,161	$33,263,095	$33,141,029	$33,018,963	$32,896,897	$32,774,831	$32,652,765	$32,530,699	$32,408,633	$32,286,567	$32,164,501	$32,042,435	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$837,053	$833,899	$830,605	$827,307	$824,144	$820,981	$826,126	$822,928	$819,730	$816,522	$813,313	$810,432	$9,883,040
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$147,621	$147,065	$146,483	$145,901	$145,343	$144,785	$138,162	$137,627	$137,092	$136,555	$136,018	$135,536	$1,698,187
8. Investment Expenses														
a. Depreciation [d]		$432,418	$432,167	$432,174	$432,118	$431,993	$431,993	$431,993	$431,991	$431,990	$431,984	$431,978	$432,531	$5,185,329
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($160,395)	($1,924,740)
9. Total System Recoverable Costs (Lines 7 & 8)		$1,268,885	$1,264,922	$1,261,055	$1,257,118	$1,253,272	$1,249,551	$1,248,072	$1,244,338	$1,240,603	$1,236,852	$1,233,101	$1,230,291	$14,988,059

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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38 - Space Coast Next Generation Solar Energy Center	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	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	($301)	$0	($10,800)	$0	($37,455)	$0	$0	$0	$0	$0	$0	$0	($48,556)
c. Retirements	$0	$0	$0	($6,741)	$0	($37,455)	$0	$0	$0	$0	$0	$0	$0	($44,196)
d. Other	$0	$0	$0	($4,059)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4,059)
2. Plant-In Service/Depreciation Base [a]	$70,650,306	$70,650,005	$70,650,005	$70,639,205	$70,639,205	$70,601,750	$70,601,750	$70,601,750	$70,601,750	$70,601,750	$70,601,750	$70,601,750	$70,601,750	
3a. Less: Accumulated Depreciation	$15,914,281	$16,114,861	$16,315,439	$16,505,172	$16,705,658	$16,868,467	$17,068,508	$17,268,549	$17,468,590	$17,668,631	$17,868,672	$18,068,713	$18,268,753	
3b. Less: Capital Recovery Unamortized Balance	$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)	$54,736,024	$54,535,145	$54,334,566	$54,134,033	$53,933,546	$53,733,283	$53,533,242	$53,333,201	$53,133,160	$52,933,119	$52,733,078	$52,533,037	$52,332,997	
6. Average Net Investment		$54,635,585	$54,434,855	$54,234,300	$54,033,790	$53,833,415	$53,633,262	$53,433,221	$53,233,180	$53,033,140	$52,833,099	$52,633,058	$52,433,017	
a. Average ITC Balance		$14,281,599	$14,230,410	$14,179,221	$14,128,032	$14,076,843	$14,025,654	$13,974,465	$13,923,276	$13,872,087	$13,820,898	$13,769,709	$13,718,520	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$387,421	$386,000	$384,581	$383,162	$381,744	$380,327	$382,611	$381,182	$379,752	$378,322	$376,892	$375,463	$4,577,456
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$68,400	$68,149	$67,898	$67,648	$67,397	$67,147	$64,090	$63,851	$63,611	$63,372	$63,132	$62,893	$787,588
8. Investment Expenses														
a. Depreciation [d]		$196,187	$196,187	$196,141	$196,095	$195,872	$195,649	$195,649	$195,649	$195,649	$195,649	$195,649	$195,649	$2,350,023
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($67,263)	($807,156)
9. Total System Recoverable Costs (Lines 7 & 8)		$589,137	$587,465	$585,749	$584,033	$582,142	$580,252	$579,480	$577,810	$576,141	$574,472	$572,802	$571,133	$6,960,615

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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39 - Martin Next Generation Solar Energy Center	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	Total
1. Investments														
a. Expenditures/Additions	$0	$265,626	$709,327	$9,378	$173,636	($330,037)	($1,052,026)	($205,953)	$144,922	$53,006	$118,162	$438,170	$208,937	$533,149
b. Clearings to Plant	$0	$258,639	($34,426)	$52,033	($52,373)	$694,336	$614,510	$20,367	($30,148)	$46	$2,623	($464)	$15,749	$1,540,894
c. Retirements	$0	($361,777)	$0	($106,929)	($47,794)	$0	($536,251)	$0	$0	$0	$0	$0	($45,086)	($1,097,837)
d. Other	$0	($66,874)	($93,382)	$27,469	($22,473)	($23,941)	($2,117)	$33,037	($5,823)	$0	($6,731)	($30,692)	($8,409)	($199,937)
2. Plant-In Service/Depreciation Base [a]	$422,853,922	$423,112,561	$423,078,135	$423,130,169	$423,077,796	$423,772,131	$424,386,641	$424,407,008	$424,376,860	$424,376,907	$424,379,530	$424,379,066	$424,394,815	
3a. Less: Accumulated Depreciation	$79,701,478	$80,341,013	$81,316,330	$82,305,635	$83,304,133	$84,349,730	$84,882,473	$85,987,384	$87,053,430	$88,125,271	$89,190,383	$90,231,546	$91,249,931	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$1,321,775	$1,587,401	$2,296,728	$2,306,106	$2,479,742	$2,149,705	$1,097,679	$891,726	$1,036,648	$1,089,655	$1,207,816	$1,645,986	$1,854,924	
5. Net Investment (Lines 2 - 3 + 4)	$344,474,219	$344,358,949	$344,058,533	$343,130,640	$342,253,406	$341,572,107	$340,601,847	$339,311,350	$338,360,079	$337,341,291	$336,396,963	$335,793,507	$334,999,808	
6. Average Net Investment		$344,416,584	$344,208,741	$343,594,586	$342,692,023	$341,912,756	$341,086,977	$339,956,599	$338,835,715	$337,850,685	$336,869,127	$336,095,235	$335,396,658	
a. Average ITC Balance		$98,597,929	$98,254,131	$97,910,333	$97,566,535	$97,222,737	$96,878,939	$96,535,141	$96,191,343	$95,847,545	$95,503,747	$95,159,949	$94,816,151	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$2,461,194	$2,459,081	$2,454,321	$2,447,682	$2,441,847	$2,435,708	$2,452,195	$2,444,050	$2,436,794	$2,429,561	$2,423,687	$2,418,306	$29,304,425
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$434,024	$433,668	$432,838	$431,673	$430,651	$429,574	$410,142	$408,781	$407,573	$406,369	$405,396	$404,508	$5,035,197
8. Investment Expenses														
a. Depreciation [d]		$1,018,631	$1,019,145	$1,019,210	$1,019,210	$1,019,983	$1,021,556	$1,022,318	$1,022,314	$1,022,286	$1,022,289	$1,022,299	$1,022,325	$12,251,567
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($451,751)	($5,421,012)
9. Total System Recoverable Costs (Lines 7 & 8)		$3,511,653	$3,509,697	$3,504,173	$3,496,369	$3,490,284	$3,484,643	$3,482,459	$3,472,949	$3,464,457	$3,456,022	$3,449,186	$3,442,943	$41,764,837

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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41 - Manatee Temporary Heating System	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	Total
1. Investments														
a. Expenditures/Additions	$0	$0	$0	$0	$0	$0	$0	$18,514	$36,127	$0	$461,790	$46,451	$597,809	$1,160,691
b. Clearings to Plant	$0	$0	($52,273)	$0	$0	$0	$0	$0	$0	$0	($1,119)	$0	($16,244)	($69,637)
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,119)	$0	($16,244)	($17,364)
d. Other	$0	$0	($52,273)	$0	$0	$0	$20,138	$0	$0	$0	$0	$0	($193)	($32,328)
2. Plant-In Service/Depreciation Base [a]	$5,805,515	$5,805,515	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,753,241	$5,752,122	$5,752,122	$5,735,878	
3a. Less: Accumulated Depreciation	$5,554,368	$5,554,562	$5,502,891	$5,503,085	$5,503,278	$5,503,471	$5,523,803	$5,523,996	$5,524,190	$5,524,383	$5,523,457	$5,523,651	$5,507,310	
3b. Less: Capital Recovery Unamortized Balance	$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	$18,514	$54,642	$54,642	$516,431	$562,882	$1,160,691	
5. Net Investment (Lines 2 - 3 + 4)	$251,146	$250,953	$250,350	$250,157	$249,963	$249,770	$229,438	$247,759	$283,693	$283,500	$745,096	$791,354	$1,389,259	
6. Average Net Investment		$251,050	$250,652	$250,253	$250,060	$249,867	$239,604	$238,599	$265,726	$283,597	$514,298	$768,225	$1,090,306	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,635	$1,633	$1,630	$1,629	$1,627	$1,561	$1,562	$1,739	$1,856	$3,367	$5,029	$7,137	$30,405
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$293	$292	$292	$291	$291	$279	$267	$297	$317	$575	$859	$1,219	$5,271
8. Investment Expenses														
a. Depreciation [d]		$193	$603	$193	$193	$193	$193	$193	$193	$193	$193	$193	$97	$2,633
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,121	$2,527	$2,115	$2,113	$2,112	$2,033	$2,022	$2,230	$2,367	$4,135	$6,081	$8,453	$38,309

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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42 - Turkey Point Cooling Canal Monitoring Plan	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	Total
1. Investments														
a. Expenditures/Additions	$0	$198,623	$186,781	$942,232	$463,409	$276,597	$408,217	$793,223	$1,301,797	$1,479,660	$3,196,744	$1,847,488	$1,327,435	$12,422,206
b. Clearings to Plant	$0	($130,651)	$0	($25,796)	$2,749	$49,710	$0	$0	$0	$0	$0	$0	$0	($103,988)
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$17,170,089	$17,039,438	$17,039,438	$17,013,641	$17,016,390	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$17,066,101	$17,066,101	
3a. Less: Accumulated Depreciation	$549,921	$594,536	$638,980	$683,391	$727,772	$772,221	$816,735	$861,249	$905,763	$950,278	$994,792	$1,039,306	$1,083,820	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$6,953,906	$7,152,528	$7,339,310	$8,281,542	$8,744,951	$9,021,548	$9,429,765	$10,222,988	$11,524,785	$13,004,445	$16,201,188	$18,048,676	$19,376,111	
5. Net Investment (Lines 2 - 3 + 4)	$23,574,074	$23,597,431	$23,739,767	$24,611,792	$25,033,570	$25,315,427	$25,679,130	$26,427,839	$27,685,122	$29,120,268	$32,272,497	$34,075,471	$35,358,392	
6. Average Net Investment		$23,585,752	$23,668,599	$24,175,780	$24,822,681	$25,174,498	$25,497,279	$26,053,485	$27,056,481	$28,402,695	$30,696,382	$33,173,984	$34,716,931	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$153,621	$154,161	$157,464	$161,678	$163,969	$166,072	$170,547	$177,113	$185,925	$200,939	$217,158	$227,258	$2,135,905
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$27,484	$27,581	$28,172	$28,926	$29,336	$29,712	$29,123	$30,244	$31,749	$34,312	$37,082	$38,807	$372,527
8. Investment Expenses														
a. Depreciation [d]		$44,615	$44,445	$44,411	$44,381	$44,449	$44,514	$44,514	$44,514	$44,514	$44,514	$44,514	$44,514	$533,899
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$225,721	$226,186	$230,047	$234,984	$237,754	$240,298	$244,184	$251,870	$262,188	$279,766	$298,754	$310,579	$3,042,331

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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44 - Martin Plant Barley Barber Swamp Iron Mitigation	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	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	$0
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	$164,719	
3a. Less: Accumulated Depreciation	$19,114	$19,460	$19,806	$20,152	$20,498	$20,844	$21,190	$21,536	$21,882	$22,228	$22,574	$22,919	$23,265	
3b. Less: Capital Recovery Unamortized Balance	$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)	$145,604	$145,258	$144,912	$144,566	$144,220	$143,875	$143,529	$143,183	$142,837	$142,491	$142,145	$141,799	$141,453	
6. Average Net Investment		$145,431	$145,085	$144,739	$144,393	$144,048	$143,702	$143,356	$143,010	$142,664	$142,318	$141,972	$141,626	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$947	$945	$943	$940	$938	$936	$938	$936	$934	$932	$929	$927	$11,246
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$169	$169	$169	$168	$168	$167	$160	$160	$159	$159	$159	$158	$1,966
8. Investment Expenses														
a. Depreciation [d]		$346	$346	$346	$346	$346	$346	$346	$346	$346	$346	$346	$346	$4,151
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$1,463	$1,460	$1,457	$1,455	$1,452	$1,449	$1,445	$1,442	$1,439	$1,437	$1,434	$1,431	$17,363

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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45 - 800 MW Unit ESP	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	Total
1. Investments														
a. Expenditures/Additions	$0	$16,877	$9,625	($2,838)	$0	($23,664)	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant	$0	$7,781	$3,385	$76	$31,649	($44,692)	$0	$0	$0	$0	$0	$0	$0	($1,801)
c. Retirements	$0	$0	$0	$0	$0	($77,442)	$0	$0	$0	$0	$0	$0	$0	($77,442)
d. Other	$0	($824)	($745)	$218	($766)	($211)	$0	$0	$0	$0	$0	$0	$0	($2,328)
2. Plant-In Service/Depreciation Base [a]	$214,906,214	$214,913,995	$214,917,380	$214,917,457	$214,949,105	$214,904,413	$214,904,413	$214,904,413	$214,904,413	$214,904,413	$214,904,413	$214,904,413	$214,904,413	
3a. Less: Accumulated Depreciation	$17,315,970	$18,143,730	$18,971,588	$19,800,416	$20,628,315	$21,379,299	$22,207,851	$23,036,403	$23,864,955	$24,693,507	$25,522,059	$26,350,611	$27,179,395	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$0	$16,877	$26,502	$23,664	$23,664	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$197,590,244	$196,787,143	$195,972,294	$195,140,705	$194,344,455	$193,525,114	$192,696,562	$191,868,010	$191,039,458	$190,210,906	$189,382,354	$188,553,802	$187,725,018	
6. Average Net Investment		$197,188,693	$196,379,718	$195,556,500	$194,742,580	$193,934,784	$193,110,838	$192,282,286	$191,453,734	$190,625,182	$189,796,630	$188,968,078	$188,139,410	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$1,284,351	$1,279,082	$1,273,720	$1,268,419	$1,263,157	$1,257,791	$1,258,686	$1,253,262	$1,247,838	$1,242,415	$1,236,991	$1,231,567	$15,097,278
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$229,784	$228,841	$227,882	$226,934	$225,992	$225,032	$214,933	$214,007	$213,081	$212,155	$211,229	$210,302	$2,640,171
8. Investment Expenses														
a. Depreciation [d]		$828,584	$828,603	$828,609	$828,666	$828,637	$828,552	$828,552	$828,552	$828,552	$828,552	$828,552	$828,784	$9,943,195
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$2,342,719	$2,336,526	$2,330,211	$2,324,018	$2,317,787	$2,311,375	$2,302,171	$2,295,821	$2,289,471	$2,283,121	$2,276,772	$2,270,653	$27,680,644

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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54 - Coal Combustion Residuals	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	Total
1. Investments														
a. Expenditures/Additions	$0	$763,706	$204,630	$373,530	$586,516	$554,383	$667,969	$521,536	$851,471	$876,983	$1,636,520	$1,834,341	$12,289,551	$21,161,136
b. Clearings to Plant	$0	($1,216)	$166	($166)	$1,114	$345	$334	$0	$0	$0	$0	$0	$5,391	$5,968
c. Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In Service/Depreciation Base [a]	$254,590	$253,373	$253,539	$253,373	$254,488	$254,832	$255,167	$255,167	$255,167	$255,167	$255,167	$255,167	$260,558	
3a. Less: Accumulated Depreciation	$486	$787	$1,086	$1,386	$1,687	$1,988	$2,289	$2,590	$2,892	$3,193	$3,495	$3,796	$4,101	
3b. Less: Capital Recovery Unamortized Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4. CWIP - Non Interest Bearing	$3,026,212	$3,789,917	$3,994,548	$4,368,078	$4,954,595	$5,508,977	$6,176,946	$6,698,482	$7,549,953	$8,426,936	$10,063,456	$11,897,797	$24,187,348	
5. Net Investment (Lines 2 - 3 + 4)	$3,280,315	$4,042,504	$4,247,001	$4,620,065	$5,207,396	$5,761,822	$6,429,824	$6,951,058	$7,802,228	$8,678,909	$10,315,128	$12,149,168	$24,443,805	
6. Average Net Investment		$3,661,410	$4,144,753	$4,433,533	$4,913,730	$5,484,609	$6,095,823	$6,690,441	$7,376,643	$8,240,568	$9,497,018	$11,232,148	$18,296,487	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [b][g]		$23,848	$26,996	$28,877	$32,005	$35,723	$39,704	$43,796	$48,288	$53,943	$62,168	$73,526	$119,769	$588,642
b. Debt Component (Line 6 x debt rate x 1/12) [c][g]		$4,267	$4,830	$5,166	$5,726	$6,391	$7,103	$7,479	$8,246	$9,211	$10,616	$12,555	$20,452	$102,042
8. Investment Expenses														
a. Depreciation [d]		$301	$300	$300	$300	$301	$301	$301	$301	$301	$301	$301	$305	$3,615
b. Amortization [e]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [f]		$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. Amortization ITC Solar		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Costs (Lines 7 & 8)		$28,415	$32,126	$34,343	$38,031	$42,415	$47,109	$51,576	$56,835	$63,456	$73,085	$86,383	$140,526	$694,299

[a] 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 43-45.

[b] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Report and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[c] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[d] Applicable depreciation rate or rates. See Form 42-8A, pages 43-45.

[e] Applicable amortization period(s). See Form 42-8A, pages 43-45.

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

[g] For solar projects the return on investment calculation is comprised of two parts:

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

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component for the Jan. – Jun. 2017 actual period of 6.430% reflects a 10.55% return on equity and the monthly Equity Compon

Jul. – Dec. 2017 actual period of 6.557% reflects a 10.55% return on equity.

Debt Component: For the Jan. – Jun. 2017 actual period return of 1.796% and for the Jul. – Dec. 2017 actual period return of 1.716% is based on FPSC Order No. PSC-2016-0560-AS-EI.

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	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1. Working Capital Dr (Cr)														
a. 158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. 158.200 Allowances Withheld	$0	$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	$0
d. 254.900 Other Regulatory Liabilities-Gains	($5,046)	($4,699)	($4,353)	($4,006)	($3,792)	($3,432)	($3,071)	($2,728)	($2,354)	($1,986)	($1,619)	($1,252)	($885)	($34,177)
2. Total Working Capital	($5,046)	($4,699)	($4,353)	($4,006)	($3,792)	($3,432)	($3,071)	($2,728)	($2,354)	($1,986)	($1,619)	($1,252)	($885)	($34,177)
3. Average Net Working Capital Balance		($4,873)	($4,526)	($4,179)	($3,899)	($3,612)	($3,251)	($2,899)	($2,541)	($2,170)	($1,803)	($1,436)	($1,069)	($36,258)
4. Return on Average Net Working Capital Balance														
a. Equity Component grossed up for taxes [a]		($32)	($29)	($27)	($25)	($24)	($21)	($19)	($17)	($14)	($12)	($9)	($7)	($237)
b. Debt Component [b]		($6)	($5)	($5)	($5)	($4)	($4)	($3)	($3)	($2)	($2)	($2)	($1)	($42)
5. Total Return Component [e]		($37)	($35)	($32)	($30)	($28)	($25)	($22)	($19)	($17)	($14)	($11)	($8)	($278)
6. Expense Dr (Cr)														
a. 411.800 Gains from Dispositions of Allowances		($347)	($347)	($347)	($347)	($361)	($361)	($361)	($374)	($367)	($367)	($367)	($119,547)	($123,492)
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) [f]		($347)	($347)	($347)	($347)	($361)	($361)	($361)	($374)	($367)	($367)	($367)	($119,547)	($123,492)
8. Total System Recoverable Expenses (Lines 5+7)		($384)	($381)	($379)	($377)	($389)	($386)	($383)	($394)	($384)	($381)	($378)	($119,555)	($123,771)
a. Recoverable Costs Allocated to Energy		($384)	($381)	($379)	($377)	($389)	($386)	($383)	($394)	($384)	($381)	($378)	($119,555)	($123,771)
b. Recoverable Costs Allocated to Demand		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Energy Jurisdictional Factor		94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	94.89172%	
10. Demand Jurisdictional Factor		95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	95.04658%	
11. Retail Energy-Related Recoverable Costs [c]		($365)	($362)	($359)	($357)	($369)	($366)	($364)	($374)	($364)	($361)	($359)	($113,448)	($117,448)
12. Retail Demand-Related Recoverable Costs [d]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13. Total Jurisdictional Recoverable Costs (Lines11+12)		($365)	($362)	($359)	($357)	($369)	($366)	($364)	($374)	($364)	($361)	($359)	($113,448)	($117,448)

[a] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component for the Jan. – Jun. 2017 actual period is 4.8009% based on FPSC Order No. PSC-2016-0560-AS-EI and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2017 actual period is 4.8251% based on the May 2017 ROR Surveillance Reportt and reflects a 10.55% return on equity, per FPSC Order No. PSC-2016-0560-AS-EI.

[b] The Debt Component for the Jan. – Jun. 2017 actual period is 1.3984% based on rate case Order No. PSC-2016-0560-AS-EI and the Debt Component for the Jul. – Dec. 2017 actual period is 1.3413% based on the May 2017 ROR Surveillance Report.

[c] Line 8a times Line 9

[d] Line 8b times Line 10

[e] Line 5 is Reportted on Capital Schedule

[f] Line 7 is Reportted on O&M Schedule

Florida Power & Light Company
Environmental Cost Recovery Clause
2017 Annual Capital Depreciation Schedule

FORM 42-8A

Project	Function	Unit	Utility	Depreciation Rate / Amortization Period	Plant Balance December 2016	Plant Balance December 2017
002-LOW NOX BURNER TECHNOLOGY	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%	-	-
002-LOW NOX BURNER TECHNOLOGY Total					-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	65,605	65,605
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31100	1.74%	56,430	56,430
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U1	31200	4.64%	558,926	424,505
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31100	1.83%	56,333	56,333
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Manatee U2	31200	4.99%	599,476	468,728
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31200	4.45%	31,632	31,632
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31650	5-Year	58,207	58,207
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin Comm	31670	7-Year	66,897	66,897
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31100	2.68%	36,811	36,811
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U1	31200	4.53%	533,645	338,939
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31100	2.39%	36,845	36,845
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Martin U2	31200	4.64%	529,520	335,746
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Scherer U4	31200	2.79%	515,653	515,653
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	43,193	43,193
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP U1	31200	2.12%	780	780
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	SJRPP U2	31200	2.35%	780	780
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt Comm	31200	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	02 - Steam Generation Plant	Turkey Pt U1	31200	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	58,860	58,860
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale Comm	34500	1.60%	34,502	34,502
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	10,225	10,225
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U4	34300	4.11%	487,395	441,310
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtLauderdale U5	34300	5.00%	498,340	556,314
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U2	34300	3.46%	165,032	368,561
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	FtMyers U3 SC Peaker	34300	4.54%	2,283	141,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Manatee U3	34300	3.35%	87,691	87,691
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U3	34300	4.49%	421,385	499,129
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U4	34300	3.92%	413,986	491,342
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Martin U8	34300	3.37%	13,693	13,693
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U4	34300	4.00%	171,843	310,021
003-CONTINUOUS EMISSION MONITORING	05 - Other Generation Plant	Sanford U5	34300	4.12%	134,809	273,035
003-CONTINUOUS EMISSION MONITORING Total					**5,690,778**	**5,822,787**
004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
004-CLEAN CLOSURE EQUIVALENCY DEMONSTRATION Total					-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	3,111,263	3,111,263
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	174,543	174,543
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U1	31200	4.64%	104,845	104,845
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Manatee U2	31200	4.99%	127,429	127,429
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31100	2.52%	1,462,198	1,595,770
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin Comm	31200	4.45%	94,329	94,329
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U1	31100	2.68%	261,417	261,417
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Martin U2	31100	2.39%	85,078	85,078
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	42,091	42,091
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	SJRPP - Comm	31200	1.44%	2,292	2,292
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	898,111	898,111
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	584,290	584,290
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	133,479	133,479
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	FtMyers U3 SC Peaker	34200	3.58%	18,616	18,616
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	Martin Comm	34200	2.42%	455,941	455,941
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	05 - Other Generation Plant	PtEverglades GTs	34200	0.00%	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	08 - General Plant	General Plant	39000	1.50%	5,837,840	5,837,840
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total					**13,393,764**	**13,527,336**
007-RELOCATE TURBINE LUBE OIL PIPING	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	31,030	31,030
007-RELOCATE TURBINE LUBE OIL PIPING Total					**31,030**	**31,030**
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	46,882	46,882
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Manatee Comm	31670	7-Year	54,241	21,347
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31600	3.79%	23,107	23,107
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31650	5-Year	-	116,547
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Martin Comm	31670	7-Year	431,173	339,743
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	02 - Steam Generation Plant	Turkey Pt Comm	31670	7-Year	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	363,996	363,996
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	Sanford Comm	34100	2.40%	15,922	15,922
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	2,995	2,995
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39000	1.50%	4,413	4,413
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	08 - General Plant	General Plant	39190	3-Year	6,398	2,291
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total					**949,127**	**937,244**
010-REROUTE STORMWATER RUNOFF	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	117,794	117,794
010-REROUTE STORMWATER RUNOFF Total					**117,794**	**117,794**
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	524,873	524,873
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31200	2.23%	328,762	328,762
012-SCHERER DISCHARGE PIPELINE	02 - Steam Generation Plant	Scherer Comm	31400	2.08%	689	689
012-SCHERER DISCHARGE PIPELINE Total					**854,324**	**854,324**
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U1	31200	4.53%	367,906	367,906
020-WASTEWATER/STORMWATER DISCH ELIMINATION	02 - Steam Generation Plant	Martin U2	31200	4.64%	403,671	403,671
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total					**771,577**	**771,577**
021-ST.LUCIE TURTLE NETS	03 - Nuclear Generation Plant	StLucie Comm	32100	2.25%	6,909,559	6,909,559
021-ST.LUCIE TURTLE NETS Total					**6,909,559**	**6,909,559**
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	601,217	601,217
022-PIPELINE INTEGRITY MANAGEMENT	02 - Steam Generation Plant	Martin Comm	31100	2.52%	2,271,574	2,271,574
022-PIPELINE INTEGRITY MANAGEMENT Total					**2,872,791**	**2,872,791**
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	1,240,613	1,243,306
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	33,272	33,272
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee Comm	31500	2.34%	26,325	26,325
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U1	31200	4.64%	45,750	45,750
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Manatee U2	31200	4.99%	37,431	37,431
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31100	2.52%	568,374	574,162
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin Comm	31500	3.57%	34,755	34,755
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Turkey Pt Comm	31100	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32300	5.11%	712,225	712,225
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U1	32400	3.20%	745,335	745,335

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023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	StLucie U2	32300	3.86%	552,390	552,390
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	931,430	977,935
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34100	2.20%	189,219	189,219
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34200	3.09%	1,480,169	1,480,169
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale Comm	34300	5.20%	28,250	28,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34100	4.18%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtLauderdale GTs	34200	4.73%	513,250	513,250
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34100	7.40%	98,715	98,715
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34200	7.84%	629,983	629,983
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers GTs	34500	7.77%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U2	34300	3.46%	49,727	49,727
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	FtMyers U3 SC Peaker	34500	3.40%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin Comm	34100	2.24%	523,498	523,498
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin U8	34200	2.70%	84,868	84,868
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades Comm	34200	2.90%	2,728,283	2,728,283
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34100	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34200	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	PtEverglades GTs	34500	0.00%	-	-
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Sanford Comm	34100	2.40%	288,383	288,383
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Radial	35200	1.70%	6,946	6,946
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.70%	1,124,628	1,142,640
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	177,982	177,982
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission Plant - Electric	35800	1.87%	65,655	65,655
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	3,169,685	3,298,168
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	07 - Distribution Plant - Electric	Mass Distribution Plant	36670	2.00%	70,499	70,499
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	08 - General Plant	General Plant	39000	1.50%	146,691	146,691
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES Total					**16,329,193**	**16,530,675**
024-GAS REBURN	02 - Steam Generation Plant	Manatee U1	31200	4.64%	16,304,833	16,304,710
024-GAS REBURN	02 - Steam Generation Plant	Manatee U2	31200	4.99%	15,277,025	15,277,025
024-GAS REBURN Total					**31,581,858**	**31,581,736**
026-UST REPLACEMENT/REMOVAL	08 - General Plant	General Plant	39000	1.50%	115,447	115,447
026-UST REPLACEMENT/REMOVAL Total					**115,447**	**115,447**
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	CapeCana Comm CC	34100	2.69%		766,645
028-CWA 316B PHASE II RULE Total						**766,645**
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee Comm	31100	3.17%	102,052	102,052
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31200	4.64%	20,059,060	20,059,060
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U1	31400	4.03%	7,240,124	7,240,124
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31200	4.99%	20,461,529	20,461,529
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Manatee U2	31400	3.72%	7,905,907	7,905,907
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31200	4.45%	518,275	518,275
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin Comm	31400	3.48%	287,258	287,258
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31200	4.53%	19,504,077	19,504,077
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U1	31400	3.35%	7,499,710	7,499,710
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31200	4.64%	20,248,975	20,224,580
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin U2	31400	4.79%	7,477,120	7,477,120
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	2,243,194	79,730
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31100	2.30%	82,366,984	82,366,984
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	254,248,896	254,475,936
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31400	1.89%	(94,224)	(94,224)
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31500	2.49%	19,615,426	19,615,426
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31600	1.88%	399,586	399,586
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer U4	31670	7-Year	12,775	12,775
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U1	31200	2.12%	27,744,107	27,746,239
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U1	31500	1.46%	446,692	446,692
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U1	31600	1.14%	9,138	9,138
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U2	31200	2.35%	26,534,954	26,534,954
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U2	31500	1.84%	426,220	426,220
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	SJRPP U2	31600	1.58%	9,591	9,591
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtLauderdale GTs	34300	8.25%	110,242	110,242
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	FtMyers GTs	34300	8.22%	57,855	57,855
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34100	2.24%	763,350	699,143
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34300	2.56%	244,343	244,343
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	Martin Comm	34500	2.04%	292,499	292,499
031-CLEAN AIR INTERSTATE RULE-CAIR	05 - Other Generation Plant	PtEverglades GTs	34300	0.00%	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	2.57%	411,775	1,313
031-CLEAN AIR INTERSTATE RULE-CAIR Total					**527,147,489**	**524,714,132**
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer Comm U3&4	31200	2.32%	(1,234,033)	(1,234,039)
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	Scherer U4	31200	2.79%	108,641,809	108,641,809
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	SJRPP U1	31200	2.12%	70,087	70,087
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	SJRPP U2	31200	2.35%	18,075	18,075
033-CLEAN AIR MERCURY RULE-CAMR Total					**107,495,938**	**107,495,932**
035-MARTIN PLANT DRINKING WATER COMP	02 - Steam Generation Plant	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	StLucie Comm	32100	2.25%	7,601,405	7,601,405
036-LOW LEV RADI WSTE-LLW	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	9,855,399	9,855,399
036-LOW LEV RADI WSTE-LLW Total					**17,456,804**	**17,456,804**
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34000	0.00%	255,507	255,507
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34100	3.49%	5,265,937	5,264,052
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34300	3.36%	115,297,818	115,292,510
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34500	3.65%	26,746,246	26,746,246
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34630	3-Year	1,886	8,469
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34650	5-Year	36,693	50,315
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto Solar	34670	7-Year	126,709	161,143
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	TransGeneratorLead	35300	2.04%	308,244	308,244
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35200	1.70%	7,427	7,427
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	695,782	695,782
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.64%	1,728,419	1,695,869
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.32%	394,418	394,418
037-DE SOTO SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.38%	191,358	191,358
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	540,994	540,994
037-DE SOTO SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	1,919,623	1,890,938
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	28,426	28,426
037-DE SOTO SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year	21,238	-
037-DE SOTO SOLAR PROJECT Total					**153,566,725**	**153,531,698**
038-SPACE COAST SOLAR PROJECT	01 - Intangible Plant	Intangible Plant	30300	various	6,359,027	6,359,027
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34100	3.45%	3,893,856	3,889,496
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34300	3.30%	51,550,587	51,550,587
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34500	3.51%	6,126,699	6,126,699
038-SPACE COAST SOLAR PROJECT	05 - Other Generation Plant	Space Coast Solar	34630	3-Year	-	-
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	51,560	14,106

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

2017 Annual Capital Depreciation Schedule **FORM 42-8A**

038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	TransGeneratorLead	35300	2.04%	789,138	789,138
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35300	2.04%	139,391	139,391
038-SPACE COAST SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35310	2.64%	1,328,699	1,328,699
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36100	1.75%	274,858	274,858
038-SPACE COAST SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36200	1.90%	62,689	62,689
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	31,858	31,858
038-SPACE COAST SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year	6,741	-
038-SPACE COAST SOLAR PROJECT Total					**70,650,306**	**70,601,750**
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34000	0.00%	216,844	216,844
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34100	2.99%	20,746,646	20,745,276
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34300	2.88%	395,612,998	397,113,924
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34500	2.99%	4,125,204	4,122,852
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34600	2.85%	1,299	1,299
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34650	5-Year	11,178	11,178
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin Solar	34670	7-Year	81,460	134,433
039-MARTIN SOLAR PROJECT	05 - Other Generation Plant	Martin U8	34300	3.37%	423,126	423,126
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35500	2.32%	603,692	603,692
039-MARTIN SOLAR PROJECT	06 - Transmission Plant - Electric	Transmission Plant - Electric	35600	2.38%	364,159	364,159
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36400	0.00%	9,282	-
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36660	1.42%	94,476	94,476
039-MARTIN SOLAR PROJECT	07 - Distribution Plant - Electric	Mass Distribution Plant	36760	1.96%	2,728	2,728
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39220	10.00%	121,101	121,101
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39240	2.63%	332,682	332,682
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39290	4.99%	88,938	88,938
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39420	7-Year	13,666	13,666
039-MARTIN SOLAR PROJECT	08 - General Plant	General Plant	39720	7-Year	4,442	4,442
039-MARTIN SOLAR PROJECT Total					**422,853,922**	**424,394,815**
041-PRV MANATEE HEATING SYSTEM	02 - Steam Generation Plant	PtEvergladesComm	31400	42 mos.	-	-
041-PRV MANATEE HEATING SYSTEM	05 - Other Generation Plant	CapeCanaveral Comm	34300	0.00%	4,042,459	4,042,459
041-PRV MANATEE HEATING SYSTEM	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	472,661	471,542
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36400	0.00%	225,952	-
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36410	various		137,247
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36420	various		36,431
041-PRV MANATEE HEATING SYSTEM	07 - Distribution Plant - Electric	Mass Distribution Plant	36500	various	307,599	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	16,244	-
041-PRV MANATEE HEATING SYSTEM Total					**5,805,515**	**5,735,878**
042-PTN COOLING CANAL MONITORING SYS	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	3.13%	17,170,089	17,066,101
042-PTN COOLING CANAL MONITORING SYS Total					**17,170,089**	**17,066,101**
044-Barley Barber Swamp Iron Mitiga	02 - Steam Generation Plant	Martin Comm	31100	2.52%	164,719	164,719
044-Barley Barber Swamp Iron Mitiga Total					**164,719**	**164,719**
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee Comm	31200	7.62%	155,747	155,747
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31200	4.64%	44,989,219	44,989,219
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31500	4.11%	4,524,074	4,524,074
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U1	31600	3.91%	1,021,918	1,021,918
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31200	4.99%	51,910,750	51,910,750
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31500	4.48%	4,793,798	4,793,798
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Manatee U2	31600	4.79%	1,071,311	1,071,311
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31200	4.53%	47,161,912	47,137,592
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31500	3.12%	4,322,420	4,322,420
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U1	31600	3.81%	1,006,508	1,012,007
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31200	4.64%	48,464,683	48,445,547
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31500	3.56%	4,449,156	4,449,270
045-800 MW UNIT ESP PROJECT	02 - Steam Generation Plant	Martin U2	31600	4.31%	1,034,718	1,070,760
045-800 MW UNIT ESP PROJECT Total					**214,906,214**	**214,904,413**
054-Coal Combustion Residuals	02 - Steam Generation Plant	Scherer Comm	31100	1.51%	200,216	204,391
054-Coal Combustion Residuals	02 - Steam Generation Plant	SJRPP - Comm	31100	1.09%	54,373	56,167
054-Coal Combustion Residuals Total					**254,590**	**260,558**

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

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

FORM 42-9A

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

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

DEBT COMPONENTS:	
LONG TERM DEBT	1.3349%
SHORT TERM DEBT	0.0314%
CUSTOMER DEPOSITS	0.0261%
TAX CREDITS -WEIGHTED	0.0060%
TOTAL DEBT	**1.3984%**

EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.7794%
TAX CREDITS -WEIGHTED	0.0215%
TOTAL EQUITY	**4.8009%**
TOTAL	6.1993%
PRE-TAX EQUITY	7.8159%
PRE-TAX TOTAL	9.2143%

Note:
Convertible Investment Tax Credit (C-ITC)

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

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

FORM 42-9A

Equity @ 10.55%	**CAPITAL STRUCTURE AND COST RATES PER MAY 2017 EARNINGS SURVEILLANCE REPORT**				
	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	8,578,170,782	27.773%	4.53%	1.26%	1.26%
SHORT_TERM_DEBT	876,957,343	2.839%	1.76%	0.05%	0.05%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	421,323,778	1.364%	2.09%	0.03%	0.03%
COMMON_EQUITY	14,087,418,183	45.610%	10.55%	4.81%	7.83%
DEFERRED_INCOME_TAX	6,860,621,618	22.212%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	62,115,684	0.201%	8.27%	0.02%	0.02%
TOTAL	$30,886,607,389	100.00%		6.17%	9.20%

	CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)				
	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$8,578,170,782	37.85%	4.534%	1.716%	1.716%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	14,087,418,183	62.15%	10.550%	6.557%	10.675%
TOTAL	$22,665,588,966	100.00%		8.273%	12.391%
RATIO					

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

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

Note:

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

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

FORM: 42-1P

JANUARY 2019 THROUGH DECEMBER 2019

	Energy	CP Demand	GCP Demand	Total
1. Total Jurisdictional Revenue Requirements for the Projected Period				
a. Projected O&M Activities [a]	$25,417,047	$8,384,078	$2,675,270	$36,476,395
b. Projected Capital Projects [b]	$13,148,129	$137,741,386	$0	$150,889,515
c. Total Jurisdictional Revenue Requirements [c]	$38,565,176	$146,125,464	$2,675,270	$187,365,910
2. True-up for Actual Estimated Over/(Under) Recovery [d]	($1,403,605)	($4,098,527)	($112,288)	($5,614,420)
3. Final True-up Over/(Under) [e]	$5,365,214	$25,879,266	$315,601	$31,560,081
4. Total Jurisdictional Amount to be Recovered/(Refunded) [f]	$34,603,567	$124,344,724	$2,471,958	$161,420,249
5. Total Projected Jurisdictional Amount Adjusted for Taxes [g]	$34,628,482	$124,434,252	$2,473,737	$161,536,472

[a] Form 42-2P-1 pg. 2, Columns 7 through 9

[b] Form 42-3P-1 pg. 2, Columns 7 through 8

[c] Lines 1a + 1b

[d] For the current period January 2018 - December 2018 (Form 42-1E, Line 4, filed on July 25, 2018)

[e] For the period January 2017 - December 2017 (Revised Form 42-1A, Line 7, filed on July 25, 2018)

[f] (Line 1 - Line 2 - Line 3)

[g] Line 4 x Revenue Tax Multiplier 1.00072

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 14
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL)(DIRECT)
DESCRIPTION: Renae B. Deaton RBD-4

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

JANUARY 2019 THROUGH DECEMBER 2019

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	$11,250	$11,250	$11,250	$11,250	$11,250	$11,250	$11,250	$11,250	$11,250	$11,250	$11,250	$15,250	$139,000
1 - Air Operating Permit Fees	Intermediate	$5,823	$5,823	$5,823	$5,823	$5,823	$5,823	$5,823	$5,823	$5,823	$5,823	$5,823	$5,823	$69,881
1 - Air Operating Permit Fees	Peaking	$1,948	$1,948	$2,948	$1,948	$1,948	$1,948	$1,948	$1,948	$1,948	$1,948	$1,948	$1,948	$24,376
3 - Continuous Emission Monitoring Systems	Intermediate	$33,758	$34,080	$22,016	$22,016	$22,016	$32,918	$32,918	$22,016	$22,016	$22,016	$22,561	$204,827	$493,154
3 - Continuous Emission Monitoring Systems	Peaking	$2,806	$8,257	$5,336	$2,806	$2,820	$2,820	$2,806	$12,575	$2,820	$2,806	$2,820	$2,820	$51,492
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$0	$0	$33,798	$14,126	$0	$1,176	$25	$0	$2,282	$0	$123,064	$4,560	$179,032
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$0	$0	$136,987	$101,250	$42,339	$1,136	$0	$0	$3,218	$0	$0	$3,440	$288,370
8 - Oil Spill Clean-up/Response Equipment	Intermediate	$2,606	$2,606	$2,606	$2,606	$2,606	$2,606	$2,606	$2,606	$2,606	$2,606	$2,606	$2,606	$31,267
8 - Oil Spill Clean-up/Response Equipment	Peaking	$21,082	$21,082	$21,082	$21,082	$21,082	$21,082	$21,082	$21,082	$21,082	$21,082	$21,082	$21,082	$252,981
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	$28,060	$200	$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
19 - Substation Pollutant Discharge Prevention & Removal	Distribution	$217,939	$217,939	$217,939	$217,939	$217,939	$217,939	$217,939	$217,939	$217,939	$237,939	$237,939	$237,939	$2,675,270
19 - Substation Pollutant Discharge Prevention & Removal	Transmission	$75,670	$95,637	$75,670	$75,670	$75,670	$60,695	$60,695	$60,695	$60,695	$75,670	$135,587	$135,587	$987,940
21 - St. Lucie Turtle Nets	Base	$0	$0	$0	$0	$0	$0	$30,000	$16,000	$16,000	$16,000	$16,000	$16,000	$110,000
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($276)
22 - Pipeline Integrity Management	Intermediate	$4,936	$4,936	$4,936	$18,006	$18,006	$10,952	$4,936	$4,936	$4,936	$4,936	$4,936	$4,936	$91,385
22 - Pipeline Integrity Management	Peaking	$3,723	$3,723	$3,723	$22,153	$22,153	$12,207	$3,723	$3,723	$3,723	$3,723	$3,723	$3,723	$90,023
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$49,792	$51,092	$51,092	$49,007	$49,327	$49,222	$49,327	$50,112	$50,682	$49,007	$50,197	$51,085	$599,938
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$1,539	$1,539	$1,539	$1,539	$1,539	$1,539	$1,539	$1,539	$1,539	$1,539	$1,539	$1,539	$18,474
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$1,661	$1,661	$1,661	$1,661	$1,661	$1,661	$1,661	$1,661	$1,661	$1,661	$1,661	$1,661	$19,926
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$13,650	$13,650	$13,650	$13,650	$13,650	$13,650	$13,650	$13,650	$13,650	$13,650	$13,650	$13,650	$163,800
24 - Manatee Reburn	Peaking	$0	$0	$159,939	$0	$0	$0	$0	$0	$0	$0	$0	$0	$159,939
27 - Lowest Quality Water Source	Intermediate	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000	$156,000
28 - CWA 316(b) Phase II Rule	Base	$9,311	$1,177	$1,161	$8,981	$15,826	$15,253	$15,419	$8,981	$8,578	$8,689	$1,264	$26,004	$120,643
28 - CWA 316(b) Phase II Rule	Intermediate	$126,144	$105,440	$120,718	$89,165	$47,427	$82,358	$99,859	$126,417	$99,939	$101,964	$70,791	$62,585	$1,132,806
28 - CWA 316(b) Phase II Rule	Peaking	$13,317	$17,980	$18,461	$6,832	$12,367	$13,433	$14,361	$19,172	$11,464	$7,113	$13,313	$6,804	$154,618
29 - SCR Consumables	Intermediate	$26,903	$26,903	$40,403	$72,595	$76,903	$26,903	$39,191	$39,268	$28,264	$117,276	$28,264	$28,264	$551,133
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$308,104	$308,104	$308,104	$308,104	$308,104	$308,104	$308,104	$308,104	$308,104	$308,104	$308,104	$308,104	$3,697,248
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	$225,084	$225,084	$225,084	$225,084	$225,084	$225,084	$225,084	$225,084	$225,084	$225,084	$225,084	$225,084	$2,701,008
37 - DeSoto Next Generation Solar Energy Center	Solar	$36,855	$30,451	$124,394	$77,515	$26,331	$27,858	$31,493	$27,612	$26,946	$32,143	$31,366	$26,824	$499,789
38 - Space Coast Next Generation Solar Energy Center	Solar	$33,818	$25,409	$22,252	$26,003	$24,763	$28,185	$35,197	$29,278	$25,427	$25,360	$21,500	$22,171	$319,363
39 - Martin Next Generation Solar Energy Center	Intermediate	$256,642	$273,806	$277,909	$281,735	$285,546	$274,114	$285,546	$281,735	$277,924	$285,938	$279,984	$286,087	$3,346,966
41 - Manatee Temporary Heating System	Intermediate	$0	$0	$0	$0	$0	$0	$0	$0	$20,000	$30,000	$0	$0	$50,000
41 - Manatee Temporary Heating System	Peaking	$23,200	$23,200	$23,200	$5,200	$5,000	$5,000	$5,000	$5,000	$5,000	$20,200	$22,700	$23,200	$165,900
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$594,763	$679,426	$2,050,453	$2,098,232	$2,824,270	$3,144,454	$2,484,920	$681,837	$1,346,544	$611,506	$610,410	$608,561	$17,735,378
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	$0	$0	$0	$2,400	$0	$0	$0	$0	$2,400	$0	$0	$0	$4,800
47 - NPDES Permit Renewal Requirements	Intermediate	$0	$5,200	$15,929	$0	$4,399	$0	$0	$5,200	$5,200	$4,399	$0	$0	$40,327
48 - Industrial Boiler MACT	Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,120	$0	$0	$5,120
48 - Industrial Boiler MACT	Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,880	$0	$0	$26,880
51 - Gopher Tortoise Relocations	Intermediate	$2,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000
51 - Gopher Tortoise Relocations	Peaking	$0	$0	$0	$0	$0	$0	$0	$8,000	$8,000	$0	$0	$7,649	$23,649
54 - Coal Combustion Residuals	Base	$27,890	$27,890	$27,890	$27,890	$27,890	$27,890	$27,890	$27,890	$27,890	$27,890	$27,890	$27,890	$334,680
55 - Solar Site Avian Monitoring and Reporting	Solar	$13,383	$13,383	$13,383	$13,383	$13,383	$13,383	$13,383	$4,905	$4,905	$0	$0	$0	$103,493
	Total	$2,258,422	$2,288,277	$4,086,063	$3,867,672	$4,459,231	$4,684,468	$4,090,297	$2,298,144	$2,918,462	$2,353,148	$2,348,263	$2,430,626	$38,083,072

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

JANUARY 2019 THROUGH DECEMBER 2019
O&M ACTIVITIES

(1)	(2)	(4)	(5)	(6)	(7)	(8)	(9)
O&M Project	Strata		Jurisdictionalization		Method of Classification		
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	CP Demand	Energy	GCP Demand
1 - Air Operating Permit Fees	Base	$139,000	95.9309%	$133,344	$0	$133,344	$0
1 - Air Operating Permit Fees	Intermediate	$69,881	94.4167%	$65,980	$0	$65,980	$0
1 - Air Operating Permit Fees	Peaking	$24,376	95.5155%	$23,283	$0	$23,283	$0
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$179,032	94.2474%	$168,733	$168,733	$0	$0
5 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$288,370	95.3443%	$274,944	$274,944	$0	$0
8 - Oil Spill Clean-up/Response Equipment	Intermediate	$31,267	94.4167%	$29,521	$0	$29,521	$0
8 - Oil Spill Clean-up/Response Equipment	Peaking	$252,981	95.5155%	$241,636	$0	$241,636	$0
14 - NPDES Permit Fees	Base	$11,500	95.7589%	$11,012	$11,012	$0	$0
14 - NPDES Permit Fees	Intermediate	$28,260	94.2474%	$26,634	$26,634	$0	$0
14 - NPDES Permit Fees	Peaking	$29,440	95.3443%	$28,069	$28,069	$0	$0
19 - Substation Pollutant Discharge Prevention & Removal	Distribution	$2,675,270	100.0000%	$2,675,270	$0	$0	$2,675,270
19 - Substation Pollutant Discharge Prevention & Removal	Transmission	$987,940	89.2071%	$881,313	$881,313	$0	$0
21 - St. Lucie Turtle Nets	Base	$110,000	95.7589%	$105,335	$105,335	$0	$0
22 - Pipeline Integrity Management	Intermediate	$91,385	94.2474%	$86,128	$86,128	$0	$0
22 - Pipeline Integrity Management	Peaking	$90,023	95.3443%	$85,832	$85,832	$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	$18,474	94.2474%	$17,411	$17,411	$0	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$19,926	95.3443%	$18,999	$18,999	$0	$0
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$163,800	89.2071%	$146,121	$146,121	$0	$0
24 - Manatee Reburn	Peaking	$159,939	95.5155%	$152,767	$0	$152,767	$0
27 - Lowest Quality Water Source	Intermediate	$156,000	94.2474%	$147,026	$147,026	$0	$0
28 - CWA 316(b) Phase II Rule	Base	$120,643	95.7589%	$115,526	$115,526	$0	$0
28 - CWA 316(b) Phase II Rule	Intermediate	$1,132,806	94.2474%	$1,067,641	$1,067,641	$0	$0
28 - CWA 316(b) Phase II Rule	Peaking	$154,618	95.3443%	$147,419	$147,419	$0	$0
29 - SCR Consumables	Intermediate	$551,133	94.4167%	$520,362	$0	$520,362	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$3,697,248	95.9309%	$3,546,803	$0	$3,546,803	$0
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$132,000	95.5155%	$126,080	$0	$126,080	$0
33 - MATS Project	Base	$2,701,008	95.9309%	$2,591,101	$0	$2,591,101	$0
37 - DeSoto Next Generation Solar Energy Center	Solar	$499,789	95.7589%	$478,593	$478,593	$0	$0
38 - Space Coast Next Generation Solar Energy Center	Solar	$319,363	95.7589%	$305,819	$305,819	$0	$0
39 - Martin Next Generation Solar Energy Center	Intermediate	$3,346,966	94.2474%	$3,154,428	$3,154,428	$0	$0
3a - Continuous Emission Monitoring Systems	Intermediate	$493,154	94.4167%	$465,620	$0	$465,620	$0
3a - Continuous Emission Monitoring Systems	Peaking	$51,492	95.5155%	$49,183	$0	$49,183	$0
41 - Manatee Temporary Heating System	Intermediate	$50,000	94.4167%	$47,208	$0	$47,208	$0
41 - Manatee Temporary Heating System	Peaking	$165,900	95.5155%	$158,460	$0	$158,460	$0
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$17,735,378	95.9309%	$17,013,708	$0	$17,013,708	$0
45 - 800 MW Unit ESP	Peaking	$264,099	95.5155%	$252,256	$0	$252,256	$0
47 - NPDES Permit Renewal Requirements	Base	$4,800	95.7589%	$4,596	$4,596	$0	$0
47 - NPDES Permit Renewal Requirements	Intermediate	$40,327	94.2474%	$38,007	$38,007	$0	$0
48 - Industrial Boiler MACT	Base	$5,120	95.7589%	$4,903	$4,903	$0	$0
48 - Industrial Boiler MACT	Peaking	$26,880	95.3443%	$25,629	$25,629	$0	$0
51 - Gopher Tortoise Relocations	Intermediate	$2,000	94.2474%	$1,885	$1,885	$0	$0
51 - Gopher Tortoise Relocations	Peaking	$23,649	95.3443%	$22,548	$22,548	$0	$0
54 - Coal Combustion Residuals	Base	$334,680	95.7589%	$320,486	$320,486	$0	$0
55 - Solar Site Avian Monitoring and Reporting	Solar	$103,493	95.7589%	$99,104	$99,104	$0	$0
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($276)	95.9309%	($265)	$0	($265)	$0
	Total	$38,083,072		$36,476,395	$8,384,078	$25,417,047	$2,675,270

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

FORM: 42-2P

JANUARY 2019 THROUGH DECEMBER 2019

O&M ACTIVITIES

RAD - ECRC - 42 - 2P -2	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	$2,258,422	$2,288,277	$4,086,063	$3,867,672	$4,459,231	$4,684,468	$4,090,297	$2,298,144	$2,918,462	$2,353,148	$2,348,263	$2,430,626	$38,083,072
3. Recoverable Costs Allocated to Energy - Base	$1,139,178	$1,223,841	$2,594,868	$2,642,647	$3,368,685	$3,688,869	$3,029,335	$1,226,252	$1,890,960	$1,155,921	$1,154,826	$1,156,976	$24,272,358
Recoverable Costs Allocated to Energy - Intermediate	$69,089	$69,412	$70,847	$103,039	$107,347	$68,249	$80,537	$69,712	$78,708	$177,721	$59,253	$241,519	$1,195,436
Recoverable Costs Allocated to Energy - Peaking	$79,884	$90,911	$244,256	$60,080	$69,981	$61,699	$60,782	$79,736	$60,797	$76,884	$86,779	$78,997	$1,050,787
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$89,320	$109,287	$89,320	$89,320	$89,320	$74,345	$74,345	$74,345	$74,345	$89,320	$149,237	$149,237	$1,151,740
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$48,701	$29,067	$29,051	$39,271	$43,716	$43,143	$73,309	$52,871	$54,868	$57,699	$45,154	$69,894	$586,743
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$432,321	$404,121	$467,830	$417,572	$369,918	$383,139	$404,905	$432,827	$404,820	$411,777	$493,314	$372,706	$4,995,250
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$48,141	$23,364	$160,832	$131,896	$78,520	$28,436	$19,745	$32,556	$28,065	$39,377	$18,697	$23,277	$632,906
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$84,056	$69,243	$160,029	$116,902	$64,478	$69,427	$80,073	$61,795	$57,278	$57,503	$52,866	$48,995	$922,646
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	$217,939	$217,939	$217,939	$217,939	$217,939	$217,939	$217,939	$217,939	$217,939	$237,939	$237,939	$237,939	$2,675,270
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%	
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	$79,680	$97,492	$79,680	$79,680	$79,680	$66,321	$66,321	$66,321	$66,321	$79,680	$133,130	$133,130	$1,027,434
Jurisdictional Recoverable Costs - Production - Base	$1,139,459	$1,201,876	$2,517,099	$2,572,720	$3,273,472	$3,580,078	$2,976,268	$1,226,983	$1,866,556	$1,164,137	$1,151,074	$1,176,827	$23,846,550
Jurisdictional Recoverable Costs - Production - Intermediate	$472,683	$446,410	$507,809	$490,837	$449,992	$425,537	$457,653	$473,748	$455,846	$555,887	$520,881	$579,301	$5,836,584
Jurisdictional Recoverable Costs - Production - Peaking	$122,202	$109,111	$386,646	$183,141	$141,707	$86,045	$76,882	$107,200	$84,829	$110,980	$100,714	$97,647	$1,607,104
Jurisdictional Recoverable Costs - Production - Solar	$80,492	$66,306	$153,242	$111,944	$61,744	$66,483	$76,677	$59,174	$54,848	$55,065	$50,624	$46,917	$883,515
Jurisdictional Recoverable Costs - Distribution	$267,731	$269,031	$269,031	$266,946	$267,266	$267,161	$267,266	$268,051	$268,621	$286,946	$288,136	$289,024	$3,275,208
9. Total Jurisdictional Recoverable Costs for O&M Activities	$2,162,246	$2,190,226	$3,913,507	$3,705,268	$4,273,860	$4,491,624	$3,921,067	$2,201,477	$2,797,021	$2,252,695	$2,244,559	$2,322,847	$36,476,395

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

JANUARY 2019 THROUGH DECEMBER 2019
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	$5,038	$5,018	$4,998	$4,978	$4,958	$4,938	$4,918	$4,898	$4,878	$4,858	$4,838	$4,818	$59,135
03 - Continuous Emission Monitoring Systems	Base	$2,390	$2,382	$2,375	$2,367	$2,360	$2,352	$2,344	$2,337	$2,329	$2,321	$2,314	$2,306	$28,177
03 - Continuous Emission Monitoring Systems	Intermediate	$29,938	$29,837	$29,460	$29,085	$28,987	$28,890	$28,792	$28,694	$28,597	$28,499	$28,401	$28,304	$347,483
03 - Continuous Emission Monitoring Systems	Peaking	$18,445	$18,380	$18,107	$17,835	$17,773	$17,710	$17,648	$17,586	$17,523	$17,461	$17,399	$17,336	$213,202
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,723
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$52,199	$52,142	$52,085	$52,028	$51,971	$51,914	$51,857	$51,799	$51,742	$51,685	$51,628	$51,571	$622,622
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$20,270	$20,206	$20,142	$20,078	$20,014	$19,950	$19,886	$19,822	$19,758	$19,694	$19,630	$19,567	$239,017
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$65,469	$65,230	$64,991	$64,753	$64,514	$64,275	$64,037	$63,798	$63,559	$63,321	$63,082	$62,844	$769,873
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$143	$142	$141	$140	$139	$139	$138	$137	$136	$135	$134	$134	$1,659
08 - Oil Spill Clean-up/Response Equipment	Distribution	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$22	$261
08 - Oil Spill Clean-up/Response Equipment	General	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$27	$324
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$7,470	$7,442	$7,907	$8,368	$8,337	$8,305	$8,273	$8,241	$8,209	$8,178	$8,093	$8,009	$96,832
08 - Oil Spill Clean-up/Response Equipment	Peaking	$5,612	$5,590	$5,938	$6,285	$6,260	$6,234	$6,209	$6,183	$6,158	$6,132	$6,033	$5,934	$72,567
10 - Relocate Storm Water Runoff	Base	$530	$529	$527	$526	$525	$523	$522	$520	$519	$518	$516	$515	$6,270
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($4)	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($30)
12 - Scherer Discharge Pipeline	Base	$2,891	$2,882	$2,874	$2,866	$2,858	$2,850	$2,842	$2,834	$2,826	$2,818	$2,810	$2,801	$34,152
20 - Wastewater Discharge Elimination & Reuse	Peaking	$6,309	$6,290	$6,271	$6,253	$6,234	$6,215	$6,196	$6,177	$6,159	$6,140	$6,121	$6,102	$74,467
21 - St. Lucie Turtle Nets	Base	$60,678	$60,596	$60,513	$60,431	$60,348	$60,265	$60,183	$60,100	$60,018	$59,935	$59,853	$59,770	$722,690
22 - Pipeline Integrity Management	Intermediate	$11,789	$11,768	$11,746	$11,725	$11,703	$11,682	$11,660	$11,639	$11,617	$11,596	$11,574	$11,552	$140,050
22 - Pipeline Integrity Management	Peaking	$10,225	$10,206	$10,187	$10,168	$10,149	$10,130	$10,111	$10,092	$10,073	$10,054	$10,035	$10,016	$121,450
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$28,963	$28,885	$28,807	$28,729	$28,650	$28,572	$28,494	$28,416	$28,337	$28,259	$28,181	$28,103	$342,396
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$20,656	$20,624	$20,609	$20,593	$20,562	$20,530	$20,499	$20,475	$20,452	$20,420	$20,405	$20,409	$246,234
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$892	$891	$890	$888	$887	$886	$885	$884	$883	$881	$880	$879	$10,626
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$57,899	$58,620	$62,362	$65,862	$67,272	$68,563	$68,908	$68,726	$68,544	$68,681	$69,136	$69,859	$794,432
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$47,399	$48,464	$53,562	$57,417	$57,220	$57,023	$56,827	$56,630	$56,433	$61,222	$66,002	$65,788	$683,987
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$37,965	$37,964	$37,964	$37,963	$37,962	$37,961	$38,119	$38,436	$38,881	$39,165	$39,162	$39,159	$460,701
24 - Manatee Reburn	Intermediate	$748	$748	$748	$748	$748	$748	$748	$1,193	$1,635	$1,630	$1,625	$1,620	$12,937
24 - Manatee Reburn	Peaking	$256,455	$255,646	$254,838	$254,029	$253,221	$252,412	$251,604	$251,423	$251,239	$250,423	$249,607	$248,791	$3,029,687
26 - UST Remove/Replacement	General	$553	$552	$552	$551	$550	$549	$548	$547	$546	$545	$544	$543	$6,580
28 - CWA 316(b) Phase II Rule	Intermediate	$6,445	$6,434	$7,068	$8,346	$9,624	$10,903	$12,181	$13,459	$14,738	$16,016	$17,294	$20,833	$143,340
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$2,987,861	$2,983,194	$2,978,905	$2,974,616	$2,970,327	$2,966,038	$2,961,662	$2,957,287	$2,952,999	$2,948,711	$2,944,423	$2,942,780	$35,568,803
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	$9,903	$9,885	$9,866	$9,848	$9,829	$9,811	$9,792	$9,774	$9,755	$9,737	$9,718	$9,699	$117,617
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$940,150	$937,485	$934,819	$932,154	$929,488	$926,823	$924,157	$921,492	$918,826	$916,161	$913,495	$910,830	$11,105,881
33 - MATS Project	Base	$790,908	$789,306	$787,713	$786,121	$784,529	$782,936	$781,344	$779,752	$778,159	$776,567	$774,974	$773,892	$9,386,202
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$28,775	$29,211	$29,910	$31,084	$33,361	$36,610	$40,660	$43,893	$45,311	$46,202	$46,982	$51,852	$463,851
35 - Martin Plant Drinking Water System Compliance	Intermediate	$953	$952	$950	$948	$946	$944	$943	$941	$939	$937	$935	$934	$11,322
35 - Martin Plant Drinking Water System Compliance	Peaking	$719	$718	$716	$715	$714	$712	$711	$710	$708	$707	$706	$704	$8,541
36 - Low-Level Radioactive Waste Storage	Base	$138,173	$137,919	$137,664	$137,409	$137,155	$136,900	$136,645	$136,391	$136,136	$135,882	$135,627	$135,372	$1,641,273
37 - DeSoto Next Generation Solar Energy Center	Solar	$1,033,002	$1,030,165	$1,027,329	$1,024,492	$1,021,656	$1,018,819	$1,015,983	$1,013,176	$1,010,369	$1,007,565	$1,004,836	$1,002,075	$12,209,466
38 - Space Coast Next Generation Solar Energy Center	Solar	$479,669	$478,396	$477,122	$475,849	$474,575	$473,302	$472,028	$470,755	$469,481	$468,207	$466,934	$465,660	$5,671,978
39 - Martin Next Generation Solar Energy Center	Intermediate	$2,890,454	$2,888,031	$2,881,193	$2,874,354	$2,867,516	$2,860,677	$2,853,839	$2,847,000	$2,840,161	$2,833,323	$2,826,484	$2,819,646	$34,282,678
41 - Manatee Temporary Heating System	Distribution	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$17,411
41 - Manatee Temporary Heating System	Intermediate	$219,849	$220,786	$221,724	$222,661	$223,598	$225,180	$227,407	$228,022	$227,026	$226,029	$225,032	$224,036	$2,691,351
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$520,764	$519,978	$519,192	$518,406	$517,620	$538,063	$558,688	$558,586	$561,883	$568,260	$574,636	$577,933	$6,534,008
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$695	$694	$693	$691	$690	$689	$688	$686	$685	$684	$683	$681	$8,260
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$524	$524	$523	$522	$521	$520	$519	$518	$517	$516	$515	$514	$6,231
45 - 800 MW Unit ESP	Intermediate	$5,456	$5,438	$5,421	$5,403	$5,385	$5,367	$5,350	$5,332	$5,314	$5,296	$5,278	$5,261	$64,301
45 - 800 MW Unit ESP	Peaking	$1,964,619	$1,959,321	$1,954,022	$1,948,724	$1,943,426	$1,938,127	$1,932,829	$1,927,531	$1,922,233	$1,916,934	$1,911,636	$1,906,338	$23,225,740
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$0	$250	$751	$1,251	$1,752	$2,252	$2,752	$3,253	$3,753	$4,254	$4,754	$6,597	$31,620
54 - Coal Combustion Residuals	Base	$466,941	$470,414	$477,477	$484,540	$491,603	$498,667	$505,730	$512,793	$519,856	$526,919	$533,983	$544,637	$6,033,559
	Total	$13,238,434	$13,221,782	$13,213,299	$13,204,449	$13,190,164	$13,198,606	$13,207,803	$13,194,587	$13,181,552	$13,175,128	$13,168,582	$13,168,655	$158,363,038

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

JANUARY 2019 THROUGH DECEMBER 2019
CAPITAL INVESTMENT PROJECTS - RECOVERABLE COSTS

(1)	(2)	(4)	(5)	(6)	(7)	(8)
Capital Project	Strata		Jurisdictionalization		Method of Classification	
		Twelve Month Total	Jurisdictional Factor	Juris Twelve Month Amount	Energy	CP Demand
02 - Low NOX Burner Technology	Peaking	$59,135	95.5155%	$56,483	$56,483	$0
03 - Continuous Emission Monitoring Systems	Base	$28,177	95.9309%	$27,030	$27,030	$0
03 - Continuous Emission Monitoring Systems	Intermediate	$347,483	94.4167%	$328,082	$328,082	$0
03 - Continuous Emission Monitoring Systems	Peaking	$213,202	95.5155%	$203,641	$203,641	$0
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Base	$1,723	95.7589%	$1,650	$127	$1,523
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Intermediate	$239,017	94.2474%	$225,267	$17,328	$207,939
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	Peaking	$769,873	95.3443%	$734,030	$56,464	$677,566
05 - Maintenance of Stationary Above Ground Fuel Storage Tanks	General	$622,622	96.9214%	$603,454	$46,420	$557,034
07 - Relocate Turbine Lube Oil Underground Piping to Above Ground	Base	$1,659	95.7589%	$1,588	$122	$1,466
08 - Oil Spill Clean-up/Response Equipment	Intermediate	$96,832	94.2474%	$91,262	$7,020	$84,242
08 - Oil Spill Clean-up/Response Equipment	Peaking	$72,567	95.3443%	$69,189	$5,322	$63,867
08 - Oil Spill Clean-up/Response Equipment	Distribution	$261	100.0000%	$261	$20	$241
08 - Oil Spill Clean-up/Response Equipment	General	$324	96.9214%	$314	$24	$290
10 - Relocate Storm Water Runoff	Base	$6,270	95.7589%	$6,004	$462	$5,542
12 - Scherer Discharge Pipeline	Base	$34,152	95.7589%	$32,704	$2,516	$30,188
21 - St. Lucie Turtle Nets	Base	$722,690	95.7589%	$692,040	$53,234	$638,806
20 - Wastewater Discharge Elimination & Reuse	Peaking	$74,467	95.3443%	$71,000	$5,462	$65,539
22 - Pipeline Integrity Management	Intermediate	$140,050	94.2474%	$131,994	$10,153	$121,840
22 - Pipeline Integrity Management	Peaking	$121,450	95.3443%	$115,796	$8,907	$106,888
23 - SPCC - Spill Prevention, Control & Countermeasures	Base	$342,396	95.7589%	$327,874	$25,221	$302,653
23 - SPCC - Spill Prevention, Control & Countermeasures	Intermediate	$794,432	94.2474%	$748,731	$57,595	$691,136
23 - SPCC - Spill Prevention, Control & Countermeasures	Peaking	$683,987	95.3443%	$652,143	$50,165	$601,978
23 - SPCC - Spill Prevention, Control & Countermeasures	Transmission	$460,701	89.2071%	$410,978	$31,614	$379,364
23 - SPCC - Spill Prevention, Control & Countermeasures	Distribution	$246,234	100.0000%	$246,234	$18,941	$227,293
23 - SPCC - Spill Prevention, Control & Countermeasures	General	$10,626	96.9214%	$10,299	$792	$9,507
24 - Manatee Reburn	Intermediate	$12,937	94.4167%	$12,214	$12,214	$0
24 - Manatee Reburn	Peaking	$3,029,687	95.5155%	$2,893,821	$2,893,821	$0
26 - UST Remove/Replacement	General	$6,580	96.9214%	$6,378	$491	$5,887
28 - CWA 316(b) Phase II Rule	Intermediate	$143,340	94.2474%	$135,094	$10,392	$124,702
31 - Clean Air Interstate Rule (CAIR) Compliance	Base	$35,568,803	95.7589%	$34,060,294	$2,620,023	$31,440,271
31 - Clean Air Interstate Rule (CAIR) Compliance	Intermediate	$117,617	94.2474%	$110,851	$8,527	$102,324
31 - Clean Air Interstate Rule (CAIR) Compliance	Peaking	$11,105,881	95.3443%	$10,588,824	$814,525	$9,774,299
31 - Clean Air Interstate Rule (CAIR) Compliance	Distribution	$103	100.0000%	$103	$8	$95
33 - MATS Project	Base	$9,386,202	95.7589%	$8,988,123	$691,394	$8,296,729
34 - St Lucie Cooling Water System Inspection & Maintenance	Base	$463,851	95.7589%	$444,178	$34,168	$410,011
35 - Martin Plant Drinking Water System Compliance	Intermediate	$11,322	94.2474%	$10,670	$821	$9,850
35 - Martin Plant Drinking Water System Compliance	Peaking	$8,541	95.3443%	$8,143	$626	$7,517
36 - Low-Level Radioactive Waste Storage	Base	$1,641,273	95.7589%	$1,571,665	$120,897	$1,450,768
37 - DeSoto Next Generation Solar Energy Center	Solar	$12,209,466	95.7589%	$11,691,650	$899,358	$10,792,293
38 - Space Coast Next Generation Solar Energy Center	Solar	$5,671,978	95.7589%	$5,431,424	$417,802	$5,013,622
39 - Martin Next Generation Solar Energy Center	Intermediate	$34,282,678	94.2474%	$32,310,533	$2,485,426	$29,825,107
41 - Manatee Temporary Heating System	Intermediate	$2,691,351	94.2474%	$2,536,528	$195,118	$2,341,410
41 - Manatee Temporary Heating System	Distribution	$17,411	100.0000%	$17,411	$1,339	$16,072
42 - Turkey Point Cooling Canal Monitoring Plan	Base	$6,534,008	95.7589%	$6,256,894	$481,300	$5,775,595
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Intermediate	$8,260	94.2474%	$7,785	$0	$7,785
44 - Martin Plant Barley Barber Swamp Iron Mitigation	Peaking	$6,231	95.3443%	$5,941	$0	$5,941
45 - 800 MW Unit ESP	Intermediate	$64,301	94.2474%	$60,602	$0	$60,602
45 - 800 MW Unit ESP	Peaking	$23,225,740	95.3443%	$22,144,419	$0	$22,144,419
50 - Steam Electric Effluent Guidelines Revised Rules	Base	$31,620	95.7589%	$30,279	$2,329	$27,950
54 - Coal Combustion Residuals	Base	$6,033,559	95.7589%	$5,777,670	$444,436	$5,333,234
NA-Amortization of Gains on Sales of Emissions Allowances	Base	($30)	95.9309%	($29)	($29)	$0
	Total	$158,363,038		$150,889,515	$13,148,129	$137,741,386

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

FORM: 42-3P

JANUARY 2019 THROUGH DECEMBER 2019
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	$13,238,434	$13,221,782	$13,213,299	$13,204,449	$13,190,164	$13,198,606	$13,207,803	$13,194,587	$13,181,552	$13,175,128	$13,168,582	$13,168,655	$158,363,038
3. Recoverable Costs Jurisdictionalized on Energy - Base	$2,387	$2,379	$2,372	$2,364	$2,357	$2,349	$2,342	$2,334	$2,327	$2,319	$2,312	$2,305	$28,147
Recoverable Costs Jurisdictionalized on Energy - Intermediate	$30,686	$30,584	$30,208	$29,833	$29,735	$29,637	$29,540	$29,887	$30,232	$30,129	$30,026	$29,923	$360,419
Recoverable Costs Jurisdictionalized on Energy - Peaking	$279,937	$279,043	$277,942	$276,842	$275,951	$275,061	$274,170	$273,907	$273,640	$272,742	$271,844	$270,946	$3,302,025
4. Recoverable Costs Jurisdictionalized on 12 CP Demand - Transmission	$37,965	$37,964	$37,964	$37,963	$37,962	$37,961	$38,119	$38,436	$38,881	$39,165	$39,162	$39,159	$460,701
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Base	$5,026,771	$5,023,449	$5,024,618	$5,026,263	$5,029,010	$5,053,959	$5,079,804	$5,084,105	$5,090,078	$5,098,602	$5,107,017	$5,124,529	$60,768,205
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Interm.	$3,231,183	$3,230,256	$3,229,070	$3,228,284	$3,224,914	$3,222,071	$3,218,926	$3,213,642	$3,206,747	$3,200,170	$3,193,859	$3,190,077	$38,589,199
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Peaking	$3,041,026	$3,033,826	$3,031,031	$3,026,990	$3,018,526	$3,010,061	$3,001,596	$2,993,131	$2,984,666	$2,981,188	$2,977,626	$2,969,070	$36,068,736
Recoverable Costs Jurisdictionalized on 12 CP Demand - Production - Solar	$1,512,671	$1,508,561	$1,504,451	$1,500,341	$1,496,231	$1,492,121	$1,488,011	$1,483,930	$1,479,850	$1,475,772	$1,471,770	$1,467,735	$17,881,445
Recoverable Costs Jurisdicitionalized on 12 CP Demand - General	$53,672	$53,613	$53,554	$53,494	$53,435	$53,376	$53,316	$53,257	$53,198	$53,139	$53,079	$53,020	$640,153
Recoverable Costs Jurisdictionalized on 12 CP Demand - Distribution	$22,137	$22,106	$22,090	$22,075	$22,043	$22,012	$21,980	$21,956	$21,933	$21,901	$21,886	$21,890	$264,009
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	$33,868	$33,867	$33,866	$33,865	$33,865	$33,864	$34,005	$34,288	$34,685	$34,938	$34,936	$34,933	$410,978
Jurisdictional Recoverable Costs - Production - Base	$4,815,870	$4,812,682	$4,813,794	$4,815,362	$4,817,986	$4,841,869	$4,866,611	$4,870,723	$4,876,435	$4,884,590	$4,892,641	$4,909,404	$58,217,966
Jurisdictional Recoverable Costs - Production - Intermediate	$3,074,278	$3,073,309	$3,071,835	$3,070,741	$3,067,473	$3,064,700	$3,061,644	$3,056,992	$3,050,819	$3,044,524	$3,038,479	$3,034,817	$36,709,613
Jurisdictional Recoverable Costs - Production - Peaking	$3,166,828	$3,159,110	$3,155,393	$3,150,490	$3,141,568	$3,132,647	$3,123,725	$3,115,403	$3,107,078	$3,102,903	$3,098,650	$3,089,634	$37,543,430
Jurisdictional Recoverable Costs - Production - Solar	$1,448,517	$1,444,582	$1,440,646	$1,436,710	$1,432,774	$1,428,838	$1,424,903	$1,420,995	$1,417,088	$1,413,183	$1,409,351	$1,405,487	$17,123,075
Jurisdictional Recoverable Costs - General	$52,020	$51,962	$51,905	$51,847	$51,790	$51,732	$51,675	$51,618	$51,560	$51,503	$51,445	$51,388	$620,445
Jurisdictional Recoverable Costs - Distribution	$22,137	$22,106	$22,090	$22,075	$22,043	$22,012	$21,980	$21,956	$21,933	$21,901	$21,886	$21,890	$264,009
8. Total Jurisdictional Recoverable Costs for Capital Investment Activities	$12,613,518	$12,597,617	$12,589,530	$12,581,090	$12,567,498	$12,575,662	$12,584,542	$12,571,976	$12,559,598	$12,553,543	$12,547,387	$12,547,553	$150,889,515

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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	($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	$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)		$1,574	$1,558	$1,541	$1,525	$1,508	$1,492	$1,475	$1,459	$1,442	$1,426	$1,410	$1,393	$17,804
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$331	$328	$324	$321	$318	$314	$311	$307	$304	$300	$297	$293	$3,748
8. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Amortization		$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$3,132	$37,583
c. Dismantlement (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)		$5,038	$5,018	$4,998	$4,978	$4,958	$4,938	$4,918	$4,898	$4,878	$4,858	$4,838	$4,818	$59,135

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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JANUARY 2019 THROUGH DECEMBER 2019

	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	$372,862	$374,061	$375,260	$376,459	$377,658	$378,857	$380,056	$381,255	$382,454	$383,652	$384,851	$386,050	$387,249	
3b. Less: Capital Recovery Unamortized Balance	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	($44,752)	
4. CWIP	$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)		$984	$978	$971	$965	$959	$952	$946	$940	$934	$927	$921	$915	$11,392
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$207	$206	$204	$203	$202	$201	$199	$198	$197	$195	$194	$193	$2,398
8. Investment Expenses														
a. Depreciation		$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$14,387
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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)		$2,390	$2,382	$2,375	$2,367	$2,360	$2,352	$2,344	$2,337	$2,329	$2,321	$2,314	$2,306	$28,177

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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		$0	$0	($33,178)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($33,178)
c. Retirements		$0	$0	($33,178)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($33,178)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$3,635,763	$3,635,763	$3,635,763	$3,602,586	$3,602,586	$3,602,586	$3,602,586	$3,602,586	$3,602,586	$3,602,586	$3,602,586	$3,602,586	$3,602,586	
3a. Less: Accumulated Depreciation	$1,653,431	$1,666,892	$1,680,353	$1,660,361	$1,673,269	$1,686,177	$1,699,086	$1,711,994	$1,724,902	$1,737,811	$1,750,719	$1,763,627	$1,776,536	
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	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,214,396	$2,198,517	$2,182,639	$2,167,037	$2,151,711	$2,136,385	$2,121,060	$2,105,734	$2,090,408	$2,075,083	$2,059,757	$2,044,431	$2,029,106	
6. Average Net Investment		$2,206,457	$2,190,578	$2,174,838	$2,159,374	$2,144,048	$2,128,722	$2,113,397	$2,098,071	$2,082,745	$2,067,420	$2,052,094	$2,036,769	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$11,614	$11,531	$11,448	$11,366	$11,286	$11,205	$11,124	$11,044	$10,963	$10,882	$10,802	$10,721	$133,987
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,445	$2,427	$2,410	$2,393	$2,376	$2,359	$2,342	$2,325	$2,308	$2,291	$2,274	$2,257	$28,206
8. Investment Expenses														
a. Depreciation		$13,461	$13,461	$13,185	$12,908	$12,908	$12,908	$12,908	$12,908	$12,908	$12,908	$12,908	$12,908	$156,282
b. Amortization		$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$2,417	$29,008
c. Dismantlement (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)		$29,938	$29,837	$29,460	$29,085	$28,987	$28,890	$28,792	$28,694	$28,597	$28,499	$28,401	$28,304	$347,483

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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JANUARY 2019 THROUGH DECEMBER 2019

	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	($25,029)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($25,029)
c. Retirements		$0	$0	($25,029)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($25,029)
d. Other (a)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base (b)	$2,142,060	$2,142,060	$2,142,060	$2,117,031	$2,117,031	$2,117,031	$2,117,031	$2,117,031	$2,117,031	$2,117,031	$2,117,031	$2,117,031	$2,117,031	
3a. Less: Accumulated Depreciation	$1,011,475	$1,019,919	$1,028,363	$1,011,569	$1,019,596	$1,027,622	$1,035,649	$1,043,675	$1,051,702	$1,059,729	$1,067,755	$1,075,782	$1,083,808	
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	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,299,114	$1,288,915	$1,278,716	$1,268,725	$1,258,943	$1,249,161	$1,239,379	$1,229,596	$1,219,814	$1,210,032	$1,200,250	$1,190,468	$1,180,686	
6. Average Net Investment		$1,294,014	$1,283,815	$1,273,720	$1,263,834	$1,254,052	$1,244,270	$1,234,487	$1,224,705	$1,214,923	$1,205,141	$1,195,359	$1,185,577	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$6,811	$6,758	$6,705	$6,653	$6,601	$6,550	$6,498	$6,447	$6,395	$6,344	$6,292	$6,241	$78,293
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,434	$1,423	$1,411	$1,400	$1,390	$1,379	$1,368	$1,357	$1,346	$1,335	$1,325	$1,314	$16,482
8. Investment Expenses														
a. Depreciation		$8,444	$8,444	$8,235	$8,027	$8,027	$8,027	$8,027	$8,027	$8,027	$8,027	$8,027	$8,027	$97,362
b. Amortization		$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$21,066
c. Dismantlement (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)		$18,445	$18,380	$18,107	$17,835	$17,773	$17,710	$17,648	$17,586	$17,523	$17,461	$17,399	$17,336	$213,202

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% 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 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	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	$21,854	
3b. Less: Capital Recovery Unamortized Balance	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	($44,384)	
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)		$119	$119	$119	$119	$119	$119	$119	$119	$119	$119	$119	$119	$1,423
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	$300
8. Investment Expenses														
a. Depreciation		$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 (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)		$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,723

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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)	$7,174,603	$7,174,603	$7,174,603	$7,174,603	$7,174,603	$7,174,603	$7,174,603	$7,174,603	$7,174,603	$7,174,603	$7,174,603	$7,174,603	$7,174,603	
3a. Less: Accumulated Depreciation	$385,403	$394,371	$403,340	$412,308	$421,276	$430,244	$439,213	$448,181	$457,149	$466,117	$475,086	$484,054	$493,022	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$6,789,200	$6,780,232	$6,771,263	$6,762,295	$6,753,327	$6,744,359	$6,735,390	$6,726,422	$6,717,454	$6,708,486	$6,699,517	$6,690,549	$6,681,581	
6. Average Net Investment		$6,784,716	$6,775,747	$6,766,779	$6,757,811	$6,748,843	$6,739,874	$6,730,906	$6,721,938	$6,712,970	$6,704,001	$6,695,033	$6,686,065	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$35,713	$35,666	$35,619	$35,572	$35,524	$35,477	$35,430	$35,383	$35,336	$35,288	$35,241	$35,194	$425,442
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$7,518	$7,508	$7,498	$7,488	$7,478	$7,468	$7,458	$7,448	$7,439	$7,429	$7,419	$7,409	$89,560
8. Investment Expenses														
a. Depreciation		$8,968	$8,968	$8,968	$8,968	$8,968	$8,968	$8,968	$8,968	$8,968	$8,968	$8,968	$8,968	$107,619
b. Amortization		$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)		$52,199	$52,142	$52,085	$52,028	$51,971	$51,914	$51,857	$51,799	$51,742	$51,685	$51,628	$51,571	$622,622

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2019 THROUGH DECEMBER 2019

	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)	$2,708,067	$2,708,067	$2,708,067	$2,708,067	$2,708,067	$2,708,067	$2,708,067	$2,708,067	$2,708,067	$2,708,067	$2,708,067	$2,708,067	$2,708,067	
3a. Less: Accumulated Depreciation	$1,393,237	$1,400,111	$1,406,986	$1,413,861	$1,420,735	$1,427,610	$1,434,485	$1,441,359	$1,448,234	$1,455,108	$1,461,983	$1,468,858	$1,475,732	
3b. Less: Capital Recovery Unamortized Balance	($297,029)	($293,872)	($290,716)	($287,560)	($284,403)	($281,247)	($278,090)	($274,934)	($271,777)	($268,621)	($265,464)	($262,308)	($259,151)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,611,859	$1,601,828	$1,591,797	$1,581,766	$1,571,735	$1,561,704	$1,551,673	$1,541,642	$1,531,610	$1,521,579	$1,511,548	$1,501,517	$1,491,486	
6. Average Net Investment		$1,606,843	$1,596,812	$1,586,781	$1,576,750	$1,566,719	$1,556,688	$1,546,657	$1,536,626	$1,526,595	$1,516,564	$1,506,533	$1,496,502	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$8,458	$8,405	$8,352	$8,300	$8,247	$8,194	$8,141	$8,088	$8,036	$7,983	$7,930	$7,877	$98,012
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,781	$1,769	$1,758	$1,747	$1,736	$1,725	$1,714	$1,703	$1,692	$1,680	$1,669	$1,658	$20,633
8. Investment Expenses														
a. Depreciation		$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$6,875	$82,495
b. Amortization		$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$3,156	$37,877
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)		$20,270	$20,206	$20,142	$20,078	$20,014	$19,950	$19,886	$19,822	$19,758	$19,694	$19,630	$19,567	$239,017

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2019 THROUGH DECEMBER 2019

	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)	$4,936,925	$4,936,925	$4,936,925	$4,936,925	$4,936,925	$4,936,925	$4,936,925	$4,936,925	$4,936,925	$4,936,925	$4,936,925	$4,936,925	$4,936,925	
3a. Less: Accumulated Depreciation	$2,749,473	$2,763,778	$2,778,082	$2,792,387	$2,806,691	$2,820,996	$2,835,300	$2,849,605	$2,863,909	$2,878,214	$2,892,518	$2,906,823	$2,921,127	
3b. Less: Capital Recovery Unamortized Balance	($2,228,226)	($2,205,079)	($2,181,931)	($2,158,784)	($2,135,637)	($2,112,489)	($2,089,342)	($2,066,195)	($2,043,047)	($2,019,900)	($1,996,753)	($1,973,605)	($1,950,458)	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,415,678	$4,378,226	$4,340,774	$4,303,322	$4,265,871	$4,228,419	$4,190,967	$4,153,515	$4,116,063	$4,078,611	$4,041,160	$4,003,708	$3,966,256	
6. Average Net Investment		$4,396,952	$4,359,500	$4,322,048	$4,284,597	$4,247,145	$4,209,693	$4,172,241	$4,134,789	$4,097,337	$4,059,885	$4,022,434	$3,984,982	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$23,145	$22,947	$22,750	$22,553	$22,356	$22,159	$21,962	$21,765	$21,567	$21,370	$21,173	$20,976	$264,723
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$4,872	$4,831	$4,789	$4,748	$4,706	$4,665	$4,623	$4,582	$4,540	$4,499	$4,457	$4,416	$55,727
8. Investment Expenses														
a. Depreciation		$14,304	$14,304	$14,304	$14,304	$14,304	$14,304	$14,304	$14,304	$14,304	$14,304	$14,304	$14,304	$171,654
b. Amortization		$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$23,147	$277,768
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)		$65,469	$65,230	$64,991	$64,753	$64,514	$64,275	$64,037	$63,798	$63,559	$63,321	$63,082	$62,844	$769,873

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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
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	$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	$60
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		$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$132	$1,586
b. Amortization		$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	$134	$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 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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
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	$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	$14	$14	$14	$14	$14	$14	$167
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		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$60
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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	$261

(a) Applicable to reserve salvage and removal cost.

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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	$1,003	$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	$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	$18	$18	$18	$18	$18	$18	$213
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		$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$66
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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	$324

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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		$0	$0	$42,750	$0	$0	$0	$0	$0	$0	$0	$0	$0	$42,750
b. Clearings to Plant		$0	$0	$42,750	$0	$0	$0	$0	$0	$0	$0	($8,858)	$0	$33,892
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)	$491,378	$491,378	$491,378	$534,128	$534,128	$534,128	$534,128	$534,128	$534,128	$534,128	$534,128	$525,270	$525,270	
3a. Less: Accumulated Depreciation	($12,398)	($8,121)	($3,845)	$787	$5,776	$10,765	$15,754	$20,742	$25,731	$30,720	$35,709	$31,787	$36,670	
3b. Less: Capital Recovery Unamortized Balance	$176	$174	$172	$170	$168	$167	$165	$163	$161	$159	$157	$156	$154	
4. CWIP	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	
5. Net Investment (Lines 2 - 3 + 4)	$503,603	$499,329	$495,055	$533,174	$528,187	$523,200	$518,213	$513,226	$508,240	$503,253	$498,266	$493,332	$488,450	
6. Average Net Investment		$501,466	$497,192	$514,114	$530,681	$525,694	$520,707	$515,720	$510,733	$505,746	$500,759	$495,799	$490,891	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$2,640	$2,617	$2,706	$2,793	$2,767	$2,741	$2,715	$2,688	$2,662	$2,636	$2,610	$2,584	$32,159
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$556	$551	$570	$588	$583	$577	$571	$566	$560	$555	$549	$544	$6,770
8. Investment Expenses														
a. Depreciation		$4,276	$4,276	$4,632	$4,989	$4,989	$4,989	$4,989	$4,989	$4,989	$4,989	$4,936	$4,883	$57,925
b. Amortization		($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)		$7,470	$7,442	$7,907	$8,368	$8,337	$8,305	$8,273	$8,241	$8,209	$8,178	$8,093	$8,009	$96,832

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% 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 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														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$32,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$32,250
b. Clearings to Plant		$0	$0	$32,250	$0	$0	$0	$0	$0	$0	$0	($12,489)	$0	$19,761
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)	$460,263	$460,263	$460,263	$492,513	$492,513	$492,513	$492,513	$492,513	$492,513	$492,513	$492,513	$480,023	$480,023	
3a. Less: Accumulated Depreciation	$120,373	$123,830	$127,287	$131,013	$135,007	$139,002	$142,996	$146,991	$150,985	$154,979	$158,974	$150,405	$154,250	
4. CWIP	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	
5. Net Investment (Lines 2 - 3 + 4)	$339,886	$336,429	$332,972	$361,496	$357,502	$353,507	$349,513	$345,518	$341,524	$337,530	$333,535	$329,615	$325,769	
6. Average Net Investment		$338,157	$334,700	$347,234	$359,499	$355,504	$351,510	$347,516	$343,521	$339,527	$335,532	$331,575	$327,692	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,780	$1,762	$1,828	$1,892	$1,871	$1,850	$1,829	$1,808	$1,787	$1,766	$1,745	$1,725	$21,644
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$375	$371	$385	$398	$394	$390	$385	$381	$376	$372	$367	$363	$4,556
8. Investment Expenses														
a. Depreciation		$3,457	$3,457	$3,726	$3,994	$3,994	$3,994	$3,994	$3,994	$3,994	$3,994	$3,920	$3,846	$46,366
b. Amortization		$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)		$5,612	$5,590	$5,938	$6,285	$6,260	$6,234	$6,209	$6,183	$6,158	$6,132	$6,033	$5,934	$72,567

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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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	$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)		$256	$254	$253	$252	$251	$250	$249	$247	$246	$245	$244	$243	$2,990
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$54	$54	$53	$53	$53	$53	$52	$52	$52	$52	$51	$51	$629
8. Investment Expenses														
a. Depreciation		$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$221	$2,650
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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	$527	$526	$525	$523	$522	$520	$519	$518	$516	$515	$6,270

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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
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	$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)		$1,337	$1,330	$1,323	$1,317	$1,310	$1,303	$1,296	$1,290	$1,283	$1,276	$1,270	$1,263	$15,597
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$281	$280	$279	$277	$276	$274	$273	$272	$270	$269	$267	$266	$3,283
8. Investment Expenses														
a. Depreciation		$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$1,273	$15,271
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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)		$2,891	$2,882	$2,874	$2,866	$2,858	$2,850	$2,842	$2,834	$2,826	$2,818	$2,810	$2,801	$34,152

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

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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
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)	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	$771,577	
3a. Less: Accumulated Depreciation	$242,899	$245,849	$248,799	$251,748	$254,698	$257,648	$260,597	$263,547	$266,497	$269,446	$272,396	$275,346	$278,296	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$528,678	$525,728	$522,778	$519,828	$516,879	$513,929	$510,979	$508,030	$505,080	$502,130	$499,181	$496,231	$493,281	
6. Average Net Investment		$527,203	$524,253	$521,303	$518,354	$515,404	$512,454	$509,504	$506,555	$503,605	$500,655	$497,706	$494,756	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$2,775	$2,760	$2,744	$2,728	$2,713	$2,697	$2,682	$2,666	$2,651	$2,635	$2,620	$2,604	$32,276
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$584	$581	$578	$574	$571	$568	$565	$561	$558	$555	$551	$548	$6,794
8. Investment Expenses														
a. Depreciation		$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$2,950	$35,397
b. Amortization		$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)		$6,309	$6,290	$6,271	$6,253	$6,234	$6,215	$6,196	$6,177	$6,159	$6,140	$6,121	$6,102	$74,467

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 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	($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	$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)		$39,424	$39,355	$39,287	$39,219	$39,151	$39,083	$39,014	$38,946	$38,878	$38,810	$38,742	$38,674	$468,583
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$8,299	$8,285	$8,270	$8,256	$8,242	$8,227	$8,213	$8,199	$8,184	$8,170	$8,156	$8,141	$98,642
8. Investment Expenses														
a. Depreciation		$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$12,955	$155,465
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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)		$60,678	$60,596	$60,513	$60,431	$60,348	$60,265	$60,183	$60,100	$60,018	$59,935	$59,853	$59,770	$722,690

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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	$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	$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)		$6,948	$6,931	$6,913	$6,895	$6,877	$6,860	$6,842	$6,824	$6,806	$6,788	$6,771	$6,753	$82,208
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,463	$1,459	$1,455	$1,451	$1,448	$1,444	$1,440	$1,437	$1,433	$1,429	$1,425	$1,422	$17,306
8. Investment Expenses														
a. Depreciation		$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		$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)		$11,789	$11,768	$11,746	$11,725	$11,703	$11,682	$11,660	$11,639	$11,617	$11,596	$11,574	$11,552	$140,050

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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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	$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)		$5,985	$5,969	$5,954	$5,938	$5,922	$5,907	$5,891	$5,875	$5,859	$5,844	$5,828	$5,812	$70,784
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	$1,240	$1,237	$1,233	$1,230	$1,227	$1,224	$14,901
8. Investment Expenses														
a. Depreciation		$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		$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)		$10,225	$10,206	$10,187	$10,168	$10,149	$10,130	$10,111	$10,092	$10,073	$10,054	$10,035	$10,016	$121,450

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% 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)	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	$3,242,469	
3a. Less: Accumulated Depreciation	$618,097	$630,378	$642,658	$654,938	$667,219	$679,499	$691,779	$704,060	$716,340	$728,620	$740,901	$753,181	$765,462	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$2,624,371	$2,612,091	$2,599,811	$2,587,530	$2,575,250	$2,562,970	$2,550,689	$2,538,409	$2,526,129	$2,513,848	$2,501,568	$2,489,288	$2,477,007	
6. Average Net Investment		$2,618,231	$2,605,951	$2,593,671	$2,581,390	$2,569,110	$2,556,830	$2,544,549	$2,532,269	$2,519,989	$2,507,708	$2,495,428	$2,483,147	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$13,782	$13,717	$13,652	$13,588	$13,523	$13,459	$13,394	$13,329	$13,265	$13,200	$13,135	$13,071	$161,115
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,901	$2,888	$2,874	$2,860	$2,847	$2,833	$2,820	$2,806	$2,792	$2,779	$2,765	$2,752	$33,917
8. Investment Expenses														
a. Depreciation		$12,280	$12,280	$12,280	$12,280	$12,280	$12,280	$12,280	$12,280	$12,280	$12,280	$12,280	$12,280	$147,364
b. Amortization		$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)		$28,963	$28,885	$28,807	$28,729	$28,650	$28,572	$28,494	$28,416	$28,337	$28,259	$28,181	$28,103	$342,396

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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	$5,000	$0	$0	$0	$0	$2,500	$0	$0	$5,000	$0	$12,500
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,500	$27,500
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)	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,373,917	$3,401,417	
3a. Less: Accumulated Depreciation	$921,374	$926,309	$931,244	$936,179	$941,114	$946,049	$950,984	$955,919	$960,854	$965,789	$970,724	$975,659	$980,614	
4. CWIP	$17,125	$17,125	$17,125	$22,125	$22,125	$22,125	$22,125	$22,125	$24,625	$24,625	$24,625	$29,625	$2,125	
5. Net Investment (Lines 2 - 3 + 4)	$2,469,668	$2,464,733	$2,459,798	$2,459,863	$2,454,928	$2,449,993	$2,445,058	$2,440,123	$2,437,688	$2,432,753	$2,427,818	$2,427,883	$2,422,928	
6. Average Net Investment		$2,467,201	$2,462,266	$2,459,831	$2,457,396	$2,452,461	$2,447,526	$2,442,591	$2,438,906	$2,435,221	$2,430,286	$2,427,851	$2,425,406	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$12,987	$12,961	$12,948	$12,935	$12,909	$12,883	$12,857	$12,838	$12,818	$12,792	$12,780	$12,767	$154,476
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$2,734	$2,728	$2,726	$2,723	$2,718	$2,712	$2,707	$2,703	$2,698	$2,693	$2,690	$2,688	$32,519
8. Investment Expenses														
a. Depreciation		$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,935	$4,955	$59,240
b. Amortization		$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)		$20,656	$20,624	$20,609	$20,593	$20,562	$20,530	$20,499	$20,475	$20,452	$20,420	$20,405	$20,409	$246,234

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2019 THROUGH DECEMBER 2019

	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														
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	$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)		$585	$584	$583	$582	$582	$581	$580	$579	$578	$577	$576	$575	$6,961
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$123	$123	$123	$123	$122	$122	$122	$122	$122	$121	$121	$121	$1,465
8. Investment Expenses														
a. Depreciation		$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$183	$2,200
b. Amortization		$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)		$892	$891	$890	$888	$887	$886	$885	$884	$883	$881	$880	$879	$10,626

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2019 THROUGH DECEMBER 2019

	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														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$272,861	$322,861	$201,170	$201,170	$50,585	$0	$0	$0	$100,000	$100,000	$50,000	$1,298,648
b. Clearings to Plant		$0	$0	$629,240	$0	$250,000	$252,925	$0	$0	$0	$0	$0	$250,000	$1,382,165
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)	$5,309,419	$5,309,419	$5,309,419	$5,938,660	$5,938,660	$6,188,660	$6,441,585	$6,441,585	$6,441,585	$6,441,585	$6,441,585	$6,441,585	$6,691,585	
3a. Less: Accumulated Depreciation	$954,165	$966,504	$978,844	$993,182	$1,009,517	$1,026,155	$1,043,459	$1,061,128	$1,078,797	$1,096,466	$1,114,135	$1,131,804	$1,149,901	
3b. Less: Capital Recovery Unamortized Balance	($1,015,825)	($1,004,948)	($994,071)	($983,194)	($972,317)	($961,440)	($950,563)	($939,685)	($928,808)	($917,931)	($907,054)	($896,177)	($885,300)	
4. CWIP	$83,518	$83,518	$356,379	$50,000	$251,170	$202,340	($0)	($0)	($0)	($0)	$100,000	$200,000	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$5,454,597	$5,431,381	$5,681,025	$5,978,672	$6,152,629	$6,326,284	$6,348,688	$6,320,142	$6,291,596	$6,263,050	$6,334,504	$6,405,958	$6,426,984	
6. Average Net Investment		$5,442,989	$5,556,203	$5,829,848	$6,065,650	$6,239,457	$6,337,486	$6,334,415	$6,305,869	$6,277,323	$6,298,777	$6,370,231	$6,416,471	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$28,651	$29,247	$30,687	$31,928	$32,843	$33,359	$33,343	$33,193	$33,042	$33,155	$33,531	$33,775	$386,754
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$6,031	$6,157	$6,460	$6,721	$6,914	$7,022	$7,019	$6,987	$6,956	$6,980	$7,059	$7,110	$81,416
8. Investment Expenses														
a. Depreciation		$12,340	$12,340	$14,338	$16,336	$16,638	$17,304	$17,669	$17,669	$17,669	$17,669	$17,669	$18,097	$195,736
b. Amortization		$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$10,877	$130,525
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)		$57,899	$58,620	$62,362	$65,862	$67,272	$68,563	$68,908	$68,726	$68,544	$68,681	$69,136	$69,859	$794,432

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2019 THROUGH DECEMBER 2019

	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	$384,744	$384,744	$0	$0	$0	$0	$0	$0	$1,128,258	$0	$0	$1,897,745
b. Clearings to Plant		$0	$0	$887,250	$0	$0	$0	$0	$0	$0	$1,329,538	$0	$0	$2,216,788
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)	$3,324,788	$3,324,788	$3,324,788	$4,212,038	$4,212,038	$4,212,038	$4,212,038	$4,212,038	$4,212,038	$4,212,038	$5,541,576	$5,541,576	$5,541,576	
3a. Less: Accumulated Depreciation	$1,411,357	$1,423,851	$1,436,345	$1,451,656	$1,469,784	$1,487,913	$1,506,041	$1,524,169	$1,542,297	$1,560,425	$1,579,950	$1,600,870	$1,621,790	
3b. Less: Capital Recovery Unamortized Balance	($1,254,179)	($1,241,411)	($1,228,642)	($1,215,873)	($1,203,104)	($1,190,335)	($1,177,567)	($1,164,798)	($1,152,029)	($1,139,260)	($1,126,492)	($1,113,723)	($1,100,954)	
4. CWIP	$319,042	$319,042	$703,786	$201,280	$201,280	$201,280	$201,280	$201,280	$201,280	$201,280	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$3,486,653	$3,461,391	$3,820,871	$4,177,535	$4,146,638	$4,115,741	$4,084,844	$4,053,947	$4,023,050	$3,992,153	$5,088,118	$5,054,429	$5,020,740	
6. Average Net Investment		$3,474,022	$3,641,131	$3,999,203	$4,162,087	$4,131,190	$4,100,293	$4,069,396	$4,038,499	$4,007,602	$4,540,136	$5,071,274	$5,037,585	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$18,286	$19,166	$21,051	$21,908	$21,746	$21,583	$21,420	$21,258	$21,095	$23,898	$26,694	$26,517	$264,622
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$3,850	$4,035	$4,431	$4,612	$4,578	$4,543	$4,509	$4,475	$4,441	$5,031	$5,619	$5,582	$55,706
8. Investment Expenses														
a. Depreciation		$12,494	$12,494	$15,311	$18,128	$18,128	$18,128	$18,128	$18,128	$18,128	$19,524	$20,920	$20,920	$210,433
b. Amortization		$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$12,769	$153,225
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)		$47,399	$48,464	$53,562	$57,417	$57,220	$57,023	$56,827	$56,630	$56,433	$61,222	$66,002	$65,788	$683,987

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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		$6,667	$6,667	$6,666	$6,667	$6,667	$6,666	$56,667	$56,667	$56,666	$6,667	$6,667	$6,666	$230,000
b. Clearings to Plant		$6,667	$6,667	$6,666	$6,667	$6,667	$6,666	$6,667	$6,667	$156,666	$6,667	$6,667	$6,666	$230,000
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)	$5,066,498	$5,073,165	$5,079,832	$5,086,498	$5,093,165	$5,099,832	$5,106,498	$5,113,165	$5,119,832	$5,276,498	$5,283,165	$5,289,832	$5,296,498	
3a. Less: Accumulated Depreciation	$404,450	$412,714	$420,988	$429,271	$437,564	$445,866	$454,177	$462,498	$470,829	$479,296	$487,901	$496,514	$505,138	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$50,000	$100,000	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$4,662,048	$4,660,451	$4,658,844	$4,657,227	$4,655,601	$4,653,966	$4,652,320	$4,700,666	$4,749,003	$4,797,202	$4,795,264	$4,793,317	$4,791,360	
6. Average Net Investment		$4,661,249	$4,659,647	$4,658,035	$4,656,414	$4,654,784	$4,653,143	$4,676,493	$4,724,835	$4,773,102	$4,796,233	$4,794,291	$4,792,339	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$24,536	$24,527	$24,519	$24,510	$24,502	$24,493	$24,616	$24,870	$25,125	$25,246	$25,236	$25,226	$297,406
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$5,165	$5,163	$5,161	$5,160	$5,158	$5,156	$5,182	$5,236	$5,289	$5,315	$5,312	$5,310	$62,607
8. Investment Expenses														
a. Depreciation		$8,264	$8,274	$8,283	$8,293	$8,302	$8,312	$8,321	$8,330	$8,467	$8,604	$8,614	$8,623	$100,688
b. Amortization		$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)		$37,965	$37,964	$37,964	$37,963	$37,962	$37,961	$38,119	$38,436	$38,881	$39,165	$39,162	$39,159	$460,701

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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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
24 - Manatee Reburn														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$11,603	$0	$0	$0	$0	$11,603
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$128,948	$0	$0	$0	$0	$128,948
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	$128,948	$128,948	$128,948	$128,948	$128,948	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$409	$1,228	$2,047	$2,866	$3,685	
4. CWIP	$117,346	$117,346	$117,346	$117,346	$117,346	$117,346	$117,346	$117,346	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$117,346	$117,346	$117,346	$117,346	$117,346	$117,346	$117,346	$117,346	$128,539	$127,720	$126,901	$126,082	$125,264	
6. Average Net Investment		$117,346	$117,346	$117,346	$117,346	$117,346	$117,346	$117,346	$122,942	$128,130	$127,311	$126,492	$125,673	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$618	$618	$618	$618	$618	$618	$618	$647	$674	$670	$666	$662	$7,643
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$130	$130	$130	$130	$130	$130	$130	$136	$142	$141	$140	$139	$1,609
8. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$409	$819	$819	$819	$819	$3,685
b. Amortization		$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)		$748	$748	$748	$748	$748	$748	$748	$1,193	$1,635	$1,630	$1,625	$1,620	$12,937

(a) Applicable to reserve salvage and removal cost.

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
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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
24 - Manatee Reburn														
Peaking														
1. Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$16,360	$0	$0	$0	$0	$16,360
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$181,822	$0	$0	$0	$0	$181,822
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)	$31,658,006	$31,658,006	$31,658,006	$31,658,006	$31,658,006	$31,658,006	$31,658,006	$31,658,006	$31,839,828	$31,839,828	$31,839,828	$31,839,828	$31,839,828	
3a. Less: Accumulated Depreciation	$11,424,246	$11,551,124	$11,678,002	$11,804,880	$11,931,758	$12,058,636	$12,185,514	$12,312,392	$12,439,848	$12,567,880	$12,695,913	$12,823,946	$12,951,978	
4. CWIP	$165,461	$165,461	$165,461	$165,461	$165,461	$165,461	$165,461	$165,461	($0)	($0)	($0)	($0)	($0)	
5. Net Investment (Lines 2 - 3 + 4)	$20,399,221	$20,272,343	$20,145,465	$20,018,587	$19,891,709	$19,764,831	$19,637,953	$19,511,075	$19,399,980	$19,271,947	$19,143,915	$19,015,882	$18,887,849	
6. Average Net Investment		$20,335,782	$20,208,904	$20,082,026	$19,955,148	$19,828,270	$19,701,392	$19,574,514	$19,455,527	$19,335,964	$19,207,931	$19,079,898	$18,951,866	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$107,043	$106,375	$105,707	$105,039	$104,371	$103,704	$103,036	$102,409	$101,780	$101,106	$100,432	$99,758	$1,240,761
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$22,534	$22,393	$22,253	$22,112	$21,971	$21,831	$21,690	$21,558	$21,426	$21,284	$21,142	$21,000	$261,194
8. Investment Expenses														
a. Depreciation		$126,878	$126,878	$126,878	$126,878	$126,878	$126,878	$126,878	$127,455	$128,033	$128,033	$128,033	$128,033	$1,527,732
b. Amortization		$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)		$256,455	$255,646	$254,838	$254,029	$253,221	$252,412	$251,604	$251,423	$251,239	$250,423	$249,607	$248,791	$3,029,687

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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
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	$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)		$338	$337	$336	$336	$335	$334	$333	$333	$332	$331	$330	$330	$4,005
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$71	$71	$71	$71	$71	$70	$70	$70	$70	$70	$70	$69	$843
8. Investment Expenses														
a. Depreciation		$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$144	$1,732
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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)		$553	$552	$552	$551	$550	$549	$548	$547	$546	$545	$544	$543	$6,580

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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
28 - CWA 316(b) Phase II Rule														
Intermediate														
1. Investments														
a. Expenditures/Additions		$0	$0	$202,340	$202,340	$202,340	$202,340	$202,340	$202,340	$202,340	$202,340	$202,340	$202,340	$2,023,400
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,023,400	$2,023,400
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)	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$767,152	$2,790,552	
3a. Less: Accumulated Depreciation	$24,725	$26,445	$28,165	$29,884	$31,604	$33,324	$35,043	$36,763	$38,483	$40,202	$41,922	$43,642	$47,629	
4. CWIP	$0	$0	$0	$202,340	$404,680	$607,020	$809,360	$1,011,700	$1,214,040	$1,416,380	$1,618,720	$1,821,060	$0	
5. Net Investment (Lines 2 - 3 + 4)	$742,427	$740,708	$738,988	$939,608	$1,140,228	$1,340,849	$1,541,469	$1,742,089	$1,942,710	$2,143,330	$2,343,950	$2,544,571	$2,742,923	
6. Average Net Investment		$741,567	$739,848	$839,298	$1,039,918	$1,240,539	$1,441,159	$1,641,779	$1,842,400	$2,043,020	$2,243,640	$2,444,260	$2,643,747	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$3,903	$3,894	$4,418	$5,474	$6,530	$7,586	$8,642	$9,698	$10,754	$11,810	$12,866	$13,916	$99,491
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$822	$820	$930	$1,152	$1,375	$1,597	$1,819	$2,042	$2,264	$2,486	$2,708	$2,929	$20,944
8. Investment Expenses														
a. Depreciation		$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$1,720	$3,988	$22,904
b. Amortization		$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)		$6,445	$6,434	$7,068	$8,346	$9,624	$10,903	$12,181	$13,459	$14,738	$16,016	$17,294	$20,833	$143,340

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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	$118,520	$118,520	$118,520	$118,520	$118,520	$118,520	$118,520	$118,520	$118,520	$118,519	$237,039	$1,422,238
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($12,507)	$0	$0	$0	$0	$2,353,410	2,340,903
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	$3,949	$0	$0	$0	$0	$0	$3,949
2. Plant-In-Service/Depreciation Base (b)	$357,183,265	$357,183,265	$357,183,265	$357,183,265	$357,183,265	$357,183,265	$357,183,265	$357,170,758	$357,170,758	$357,170,758	$357,170,758	$357,170,758	$359,524,168	
3a. Less: Accumulated Depreciation	$68,216,762	$69,008,407	$69,800,051	$70,591,696	$71,383,341	$72,174,986	$72,966,630	$73,749,643	$74,541,139	$75,332,635	$76,124,131	$76,915,627	$77,709,397	
3b. Less: Capital Recovery Unamortized Balance	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	($55,172,833)	
4. CWIP	$931,172	$931,172	$1,049,692	$1,168,212	$1,286,732	$1,405,252	$1,523,772	$1,642,292	$1,760,812	$1,879,332	$1,997,852	$2,116,371	$0	
5. Net Investment (Lines 2 - 3 + 4)	$345,070,508	$344,278,863	$343,605,739	$342,932,614	$342,259,489	$341,586,364	$340,913,240	$340,236,240	$339,563,264	$338,890,288	$338,217,312	$337,544,335	$336,987,603	
6. Average Net Investment		$344,674,686	$343,942,301	$343,269,176	$342,596,051	$341,922,927	$341,249,802	$340,574,740	$339,899,752	$339,226,776	$338,553,800	$337,880,824	$337,265,969	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,814,288	$1,810,433	$1,806,890	$1,803,346	$1,799,803	$1,796,260	$1,792,707	$1,789,154	$1,785,611	$1,782,069	$1,778,527	$1,775,290	$21,534,378
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$381,928	$381,117	$380,371	$379,625	$378,879	$378,133	$377,385	$376,637	$375,892	$375,146	$374,400	$373,719	$4,533,232
8. Investment Expenses														
a. Depreciation		$791,645	$791,645	$791,645	$791,645	$791,645	$791,645	$791,570	$791,496	$791,496	$791,496	$791,496	$793,771	$9,501,193
b. Amortization		$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)		$2,987,861	$2,983,194	$2,978,905	$2,974,616	$2,970,327	$2,966,038	$2,961,662	$2,957,287	$2,952,999	$2,948,711	$2,944,423	$2,942,780	$35,568,803

(a) Applicable to reserve salvage and removal cost.

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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	$393	$395	$398	$401	$404	$407	$409	$412	$415	$418	$421	$423	$426	
4. CWIP	$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	$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	$12
8. Investment Expenses														
a. Depreciation		$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$34
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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														
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)	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	$1,442,067	
3a. Less: Accumulated Depreciation	$343,105	$346,016	$348,926	$351,836	$354,746	$357,657	$360,567	$363,477	$366,388	$369,298	$372,208	$375,118	$378,029	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$1,098,962	$1,096,051	$1,093,141	$1,090,231	$1,087,321	$1,084,410	$1,081,500	$1,078,590	$1,075,679	$1,072,769	$1,069,859	$1,066,949	$1,064,038	
6. Average Net Investment		$1,097,506	$1,094,596	$1,091,686	$1,088,776	$1,085,865	$1,082,955	$1,080,045	$1,077,135	$1,074,224	$1,071,314	$1,068,404	$1,065,493	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$5,777	$5,762	$5,746	$5,731	$5,716	$5,700	$5,685	$5,670	$5,654	$5,639	$5,624	$5,609	$68,313
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$1,216	$1,213	$1,210	$1,206	$1,203	$1,200	$1,197	$1,194	$1,190	$1,187	$1,184	$1,181	$14,381
8. Investment Expenses														
a. Depreciation		$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$2,910	$34,923
b. Amortization		$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)		$9,903	$9,885	$9,866	$9,848	$9,829	$9,811	$9,792	$9,774	$9,755	$9,737	$9,718	$9,699	$117,617

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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														
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)	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	$111,241,707	
3a. Less: Accumulated Depreciation	$29,197,720	$29,615,395	$30,033,070	$30,450,745	$30,868,420	$31,286,095	$31,703,771	$32,121,446	$32,539,121	$32,956,796	$33,374,471	$33,792,147	$34,209,822	
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	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$82,105,664	$81,687,347	$81,269,029	$80,850,711	$80,432,394	$80,014,076	$79,595,758	$79,177,441	$78,759,123	$78,340,806	$77,922,488	$77,504,170	$77,085,853	
6. Average Net Investment		$81,896,506	$81,478,188	$81,059,870	$80,641,553	$80,223,235	$79,804,917	$79,386,600	$78,968,282	$78,549,964	$78,131,647	$77,713,329	$77,295,011	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$431,084	$428,882	$426,680	$424,478	$422,277	$420,075	$417,873	$415,671	$413,469	$411,267	$409,065	$406,863	$5,027,684
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$90,748	$90,285	$89,821	$89,358	$88,894	$88,430	$87,967	$87,503	$87,040	$86,576	$86,113	$85,649	$1,058,385
8. Investment Expenses														
a. Depreciation		$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$417,675	$5,012,102
b. Amortization		$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)		$940,150	$937,485	$934,819	$932,154	$929,488	$926,823	$924,157	$921,492	$918,826	$916,161	$913,495	$910,830	$11,105,881

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

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

Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.

Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2019 THROUGH DECEMBER 2019

	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	$3,219	$3,219	$3,219	$3,219	$3,219	$3,219	$3,219	$3,219	$3,219	$3,218	$6,438	$38,627
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$431,614	$431,614
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)	$108,663,448	$108,663,448	$108,663,448	$108,663,448	$108,663,448	$108,663,448	$108,663,448	$108,663,448	$108,663,448	$108,663,448	$108,663,448	$108,663,448	$109,095,062	
3a. Less: Accumulated Depreciation	$24,618,317	$24,871,443	$25,124,568	$25,377,694	$25,630,820	$25,883,946	$26,137,072	$26,390,198	$26,643,324	$26,896,449	$27,149,575	$27,402,701	$27,656,329	
3b. Less: Capital Recovery Unamortized Balance	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	($88,162)	
4. CWIP	$392,987	$392,987	$396,206	$399,425	$402,644	$405,863	$409,082	$412,301	$415,520	$418,739	$421,958	$425,176	$0	
5. Net Investment (Lines 2 - 3 + 4)	$84,526,280	$84,273,154	$84,023,247	$83,773,340	$83,523,433	$83,273,526	$83,023,619	$82,773,713	$82,523,806	$82,273,899	$82,023,992	$81,774,084	$81,526,895	
6. Average Net Investment		$84,399,717	$84,148,200	$83,898,293	$83,648,387	$83,398,480	$83,148,573	$82,898,666	$82,648,759	$82,398,852	$82,148,945	$81,899,038	$81,650,489	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$444,261	$442,937	$441,621	$440,306	$438,990	$437,675	$436,359	$435,044	$433,729	$432,413	$431,098	$429,789	$5,244,221
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$93,522	$93,243	$92,966	$92,689	$92,412	$92,136	$91,859	$91,582	$91,305	$91,028	$90,751	$90,476	$1,103,968
8. Investment Expenses														
a. Depreciation		$253,126	$253,126	$253,126	$253,126	$253,126	$253,126	$253,126	$253,126	$253,126	$253,126	$253,126	$253,628	$3,038,012
b. Amortization		$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)		$790,908	$789,306	$787,713	$786,121	$784,529	$782,936	$781,344	$779,752	$778,159	$776,567	$774,974	$773,892	$9,386,202

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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		$30,552	$106,380	$113,068	$255,390	$459,240	$560,780	$710,320	$304,520	$140,610	$138,902	$106,132	$102,106	$3,028,000
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,500,614	$4,500,614
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	$4,500,614	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,219	
4. CWIP	$4,500,614	$4,531,166	$4,637,546	$4,750,614	$5,006,004	$5,465,244	$6,026,024	$6,736,344	$7,040,864	$7,181,474	$7,320,376	$7,426,508	$3,028,000	
5. Net Investment (Lines 2 - 3 + 4)	$4,500,614	$4,531,166	$4,637,546	$4,750,614	$5,006,004	$5,465,244	$6,026,024	$6,736,344	$7,040,864	$7,181,474	$7,320,376	$7,426,508	$7,524,394	
6. Average Net Investment		$4,515,890	$4,584,356	$4,694,080	$4,878,309	$5,235,624	$5,745,634	$6,381,184	$6,888,604	$7,111,169	$7,250,925	$7,373,442	$7,475,451	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$23,771	$24,131	$24,709	$25,678	$27,559	$30,244	$33,589	$36,260	$37,432	$38,167	$38,812	$39,349	$379,700
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$5,004	$5,080	$5,201	$5,406	$5,802	$6,367	$7,071	$7,633	$7,880	$8,035	$8,170	$8,283	$79,931
8. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,219	$4,219
b. Amortization		$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)		$28,775	$29,211	$29,910	$31,084	$33,361	$36,610	$40,660	$43,893	$45,311	$46,202	$46,982	$51,852	$463,851

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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
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	$28,633	$28,915	$29,197	$29,478	$29,760	$30,042	$30,324	$30,605	$30,887	$31,169	$31,451	$31,733	$32,014	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$105,540	$105,258	$104,976	$104,695	$104,413	$104,131	$103,849	$103,568	$103,286	$103,004	$102,722	$102,441	$102,159	
6. Average Net Investment		$105,399	$105,117	$104,835	$104,554	$104,272	$103,990	$103,708	$103,427	$103,145	$102,863	$102,581	$102,300	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$555	$553	$552	$550	$549	$547	$546	$544	$543	$541	$540	$538	$6,560
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$117	$116	$116	$116	$116	$115	$115	$115	$114	$114	$114	$113	$1,381
8. Investment Expenses														
a. Depreciation		$282	$282	$282	$282	$282	$282	$282	$282	$282	$282	$282	$282	$3,381
b. Amortization		$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)		$953	$952	$950	$948	$946	$944	$943	$941	$939	$937	$935	$934	$11,322

(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 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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
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	$21,600	$21,813	$22,026	$22,238	$22,451	$22,663	$22,876	$23,088	$23,301	$23,514	$23,726	$23,939	$24,151	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$79,618	$79,405	$79,193	$78,980	$78,768	$78,555	$78,342	$78,130	$77,917	$77,705	$77,492	$77,280	$77,067	
6. Average Net Investment		$79,511	$79,299	$79,086	$78,874	$78,661	$78,449	$78,236	$78,024	$77,811	$77,598	$77,386	$77,173	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$419	$417	$416	$415	$414	$413	$412	$411	$410	$408	$407	$406	$4,949
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$88	$88	$88	$87	$87	$87	$87	$86	$86	$86	$86	$86	$1,042
8. Investment Expenses														
a. Depreciation		$213	$213	$213	$213	$213	$213	$213	$213	$213	$213	$213	$213	$2,551
b. Amortization		$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	$718	$716	$715	$714	$712	$711	$710	$708	$707	$706	$704	$8,541

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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
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	$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)		$81,135	$80,924	$80,714	$80,504	$80,293	$80,083	$79,873	$79,662	$79,452	$79,242	$79,031	$78,821	$959,733
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$17,080	$17,035	$16,991	$16,947	$16,903	$16,858	$16,814	$16,770	$16,726	$16,681	$16,637	$16,593	$202,035
8. Investment Expenses														
a. Depreciation		$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$39,959	$479,506
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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)		$138,173	$137,919	$137,664	$137,409	$137,155	$136,900	$136,645	$136,391	$136,136	$135,882	$135,627	$135,372	$1,641,273

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2019 THROUGH DECEMBER 2019

	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	$5,059	$0	$10,117	$0	$0	$15,176
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$10,091	$0	$0	$55,405	$0	$65,496
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)	$153,522,789	$153,522,789	$153,522,789	$153,522,789	$153,522,789	$153,522,789	$153,522,789	$153,522,789	$153,532,879	$153,532,879	$153,532,879	$153,588,284	$153,588,284	
3a. Less: Accumulated Depreciation	$46,735,703	$47,180,872	$47,626,040	$48,071,209	$48,516,378	$48,961,547	$49,406,716	$49,851,884	$50,297,067	$50,742,264	$51,187,460	$51,632,733	$52,078,082	
4. CWIP	$50,321	$50,321	$50,321	$50,321	$50,321	$50,321	$50,321	$50,321	$45,289	$45,289	$55,406	$1	$1	
5. Net Investment (Lines 2 - 3 + 4)	$106,837,406	$106,392,238	$105,947,069	$105,501,900	$105,056,731	$104,611,562	$104,166,394	$103,721,225	$103,281,101	$102,835,904	$102,400,824	$101,955,552	$101,510,203	
6. Average Net Investment		$106,614,822	$106,169,653	$105,724,484	$105,279,316	$104,834,147	$104,388,978	$103,943,809	$103,501,163	$103,058,502	$102,618,364	$102,178,188	$101,732,877	
a. Average ITC Balance		$30,577,643	$30,577,643	$30,577,643	$30,577,643	$30,577,643	$30,577,643	$30,577,643	$30,577,643	$30,577,643	$30,577,643	$30,577,643	$30,577,643	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$621,419	$619,075	$616,732	$614,389	$612,046	$609,702	$607,359	$605,029	$602,699	$600,382	$598,065	$595,721	$7,302,618
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$126,809	$126,316	$125,823	$125,330	$124,836	$124,343	$123,850	$123,359	$122,869	$122,381	$121,893	$121,400	$1,489,209
8. Investment Expenses														
a. Depreciation		$432,982	$432,982	$432,982	$432,982	$432,982	$432,982	$432,982	$432,996	$433,010	$433,010	$433,086	$433,162	$5,196,135
b. Amortization		$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)		$1,033,002	$1,030,165	$1,027,329	$1,024,492	$1,021,656	$1,018,819	$1,015,983	$1,013,176	$1,010,369	$1,007,565	$1,004,836	$1,002,075	$12,209,466

(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 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

JANUARY 2019 THROUGH DECEMBER 2019

	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	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$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)	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	$70,587,644	
3a. Less: Accumulated Depreciation	$20,653,708	$20,853,581	$21,053,453	$21,253,326	$21,453,198	$21,653,071	$21,852,943	$22,052,816	$22,252,688	$22,452,561	$22,652,433	$22,852,306	$23,052,178	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$49,933,936	$49,734,064	$49,534,191	$49,334,319	$49,134,446	$48,934,574	$48,734,701	$48,534,829	$48,334,956	$48,135,084	$47,935,211	$47,735,339	$47,535,466	
6. Average Net Investment		$49,834,000	$49,634,128	$49,434,255	$49,234,382	$49,034,510	$48,834,637	$48,634,765	$48,434,892	$48,235,020	$48,035,147	$47,835,275	$47,635,402	
a. Average ITC Balance		$13,104,252	$13,104,252	$13,104,252	$13,104,252	$13,104,252	$13,104,252	$13,104,252	$13,104,252	$13,104,252	$13,104,252	$13,104,252	$13,104,252	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$288,124	$287,071	$286,019	$284,967	$283,915	$282,863	$281,811	$280,759	$279,707	$278,655	$277,603	$276,551	$3,388,045
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$58,936	$58,715	$58,493	$58,272	$58,050	$57,829	$57,608	$57,386	$57,165	$56,943	$56,722	$56,500	$692,619
8. Investment Expenses														
a. Depreciation		$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$195,481	$2,345,766
b. Amortization		$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)		$479,669	$478,396	$477,122	$475,849	$474,575	$473,302	$472,028	$470,755	$469,481	$468,207	$466,934	$465,660	$5,671,978

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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
39 - Martin Next Generation Solar Energy Center														
Intermediate														
1. Investments														
a. Expenditures/Additions		$581,728	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$581,728
b. Clearings to Plant		$2,128,771	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,128,771
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other (a)		($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($5,600)	($67,199)
2. Plant-In-Service/Depreciation Base (b)	$425,318,258	$427,447,029	$427,447,029	$427,447,029	$427,447,029	$427,447,029	$427,447,029	$427,447,029	$427,447,029	$427,447,029	$427,447,029	$427,447,029	$427,447,029	
3a. Less: Accumulated Depreciation	$103,076,035	$104,146,727	$105,219,973	$106,293,219	$107,366,465	$108,439,712	$109,512,958	$110,586,204	$111,659,450	$112,732,696	$113,805,943	$114,879,189	$115,952,435	
4. CWIP	$1,547,044	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$323,789,267	$323,300,303	$322,227,056	$321,153,810	$320,080,564	$319,007,318	$317,934,072	$316,860,825	$315,787,579	$314,714,333	$313,641,087	$312,567,840	$311,494,594	
6. Average Net Investment		$323,544,785	$322,763,680	$321,690,433	$320,617,187	$319,543,941	$318,470,695	$317,397,448	$316,324,202	$315,250,956	$314,177,710	$313,104,463	$312,031,217	
a. Average ITC Balance		$90,690,575	$90,690,575	$90,690,575	$90,690,575	$90,690,575	$90,690,575	$90,690,575	$90,690,575	$90,690,575	$90,690,575	$90,690,575	$90,690,575	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$1,881,680	$1,877,569	$1,871,920	$1,866,270	$1,860,621	$1,854,972	$1,849,322	$1,843,673	$1,838,024	$1,832,374	$1,826,725	$1,821,076	$22,224,226
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$384,233	$383,367	$382,178	$380,989	$379,800	$378,610	$377,421	$376,232	$375,043	$373,853	$372,664	$371,475	$4,535,866
8. Investment Expenses														
a. Depreciation		$1,026,737	$1,029,291	$1,029,291	$1,029,291	$1,029,291	$1,029,291	$1,029,291	$1,029,291	$1,029,291	$1,029,291	$1,029,291	$1,029,291	$12,348,939
b. Amortization		$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)		$2,890,454	$2,888,031	$2,881,193	$2,874,354	$2,867,516	$2,860,677	$2,853,839	$2,847,000	$2,840,161	$2,833,323	$2,826,484	$2,819,646	$34,282,678

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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JANUARY 2019 THROUGH DECEMBER 2019

	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)	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	$1,380,583	
3a. Less: Accumulated Depreciation	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	$1,152,879	
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)		$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$1,199	$14,383
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$252	$252	$252	$252	$252	$252	$252	$252	$252	$252	$252	$252	$3,028
8. Investment Expenses														
a. Depreciation		$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 (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)		$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$1,451	$17,411

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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
41 - Manatee Temporary Heating System														
Intermediate														
1. Investments														
a. Expenditures/Additions		$303,510	$303,510	$303,510	$303,510	$303,510	$505,850	$505,850	$0	$0	$0	$0	$0	$2,529,250
b. Clearings to Plant		$0	$0	$0	$0	$0	$61,479	$5,548,203	$0	$0	$0	$0	$0	$5,609,682
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)	$10,923,933	$10,923,933	$10,923,933	$10,923,933	$10,923,933	$10,923,933	$10,985,412	$16,533,615	$16,533,615	$16,533,615	$16,533,615	$16,533,615	$16,533,615	
3a. Less: Accumulated Depreciation	$4,119,794	$4,276,191	$4,432,589	$4,588,986	$4,745,383	$4,901,780	$5,058,177	$5,214,574	$5,370,971	$5,527,368	$5,683,766	$5,840,163	$5,996,560	
4. CWIP	$3,080,432	$3,383,942	$3,687,452	$3,990,962	$4,294,472	$4,597,982	$5,042,353	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$9,884,570	$10,031,683	$10,178,796	$10,325,909	$10,473,022	$10,620,135	$10,969,588	$11,319,041	$11,162,643	$11,006,246	$10,849,849	$10,693,452	$10,537,055	
6. Average Net Investment		$9,958,127	$10,105,240	$10,252,353	$10,399,465	$10,546,578	$10,794,861	$11,144,314	$11,240,842	$11,084,445	$10,928,048	$10,771,651	$10,615,253	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$52,417	$53,192	$53,966	$54,740	$55,515	$56,822	$58,661	$59,169	$58,346	$57,523	$56,699	$55,876	$672,926
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$11,034	$11,197	$11,360	$11,523	$11,686	$11,962	$12,349	$12,456	$12,282	$12,109	$11,936	$11,763	$141,659
8. Investment Expenses														
a. Depreciation		$156,397	$156,397	$156,397	$156,397	$156,397	$156,397	$156,397	$156,397	$156,397	$156,397	$156,397	$156,397	$1,876,765
b. Amortization		$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)		$219,849	$220,786	$221,724	$222,661	$223,598	$225,180	$227,407	$228,022	$227,026	$226,029	$225,032	$224,036	$2,691,351

(a) Applicable to reserve salvage and removal cost.

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% 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 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		$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 (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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% 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 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		$0	$0	$0	$0	$0	$0	$100,000	$200,000	$1,166,666	$1,166,667	$1,166,667	$200,000	$4,000,000
b. Clearings to Plant		$0	$0	$0	$0	$0	$16,329,409	$0	$0	$0	$0	$0	$0	$16,329,409
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)	$48,180,139	$48,180,139	$48,180,139	$48,180,139	$48,180,139	$48,180,139	$64,509,548	$64,509,548	$64,509,548	$64,509,548	$64,509,548	$64,509,548	$64,509,548	
3a. Less: Accumulated Depreciation	$2,076,363	$2,199,705	$2,323,046	$2,446,388	$2,569,730	$2,693,071	$2,837,709	$3,003,643	$3,169,577	$3,335,512	$3,501,446	$3,667,380	$3,833,314	
4. CWIP	$16,329,404	$16,329,404	$16,329,404	$16,329,404	$16,329,404	$16,329,404	($5)	$99,995	$299,995	$1,466,661	$2,633,328	$3,799,995	$3,999,995	
5. Net Investment (Lines 2 - 3 + 4)	$62,433,180	$62,309,838	$62,186,496	$62,063,155	$61,939,813	$61,816,471	$61,671,834	$61,605,899	$61,639,965	$62,640,697	$63,641,430	$64,642,163	$64,676,229	
6. Average Net Investment		$62,371,509	$62,248,167	$62,124,826	$62,001,484	$61,878,142	$61,744,153	$61,638,867	$61,622,932	$62,140,331	$63,141,064	$64,141,796	$64,659,196	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$328,309	$327,660	$327,011	$326,361	$325,712	$325,007	$324,453	$324,369	$327,092	$332,360	$337,628	$340,351	$3,946,313
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$69,113	$68,976	$68,839	$68,703	$68,566	$68,418	$68,301	$68,283	$68,857	$69,966	$71,074	$71,648	$830,744
8. Investment Expenses														
a. Depreciation		$123,342	$123,342	$123,342	$123,342	$123,342	$144,638	$165,934	$165,934	$165,934	$165,934	$165,934	$165,934	$1,756,951
b. Amortization		$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)		$520,764	$519,978	$519,192	$518,406	$517,620	$538,063	$558,688	$558,586	$561,883	$568,260	$574,636	$577,933	$6,534,008

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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	$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	$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)		$411	$410	$409	$408	$407	$406	$405	$404	$403	$402	$401	$400	$4,869
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$87	$86	$86	$86	$86	$86	$85	$85	$85	$85	$84	$84	$1,025
8. Investment Expenses														
a. Depreciation		$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$197	$2,366
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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)		$695	$694	$693	$691	$690	$689	$688	$686	$685	$684	$683	$681	$8,260

(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 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% 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 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	$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	$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)		$310	$310	$309	$308	$307	$306	$306	$305	$304	$303	$303	$302	$3,673
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$65	$65	$65	$65	$65	$65	$64	$64	$64	$64	$64	$64	$773
8. Investment Expenses														
a. Depreciation		$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$149	$1,785
b. Amortization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement (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)		$524	$524	$523	$522	$521	$520	$519	$518	$517	$516	$515	$514	$6,231

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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

FORM: 42-4P

JANUARY 2019 THROUGH DECEMBER 2019

	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)	$439,587	$439,587	$439,587	$439,587	$439,587	$439,587	$439,587	$439,587	$439,587	$439,587	$439,587	$439,587	$439,587	
3a. Less: Accumulated Depreciation	$19,977	$22,768	$25,560	$28,351	$31,142	$33,934	$36,725	$39,517	$42,308	$45,100	$47,891	$50,682	$53,474	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$419,611	$416,819	$414,028	$411,236	$408,445	$405,654	$402,862	$400,071	$397,279	$394,488	$391,696	$388,905	$386,113	
6. Average Net Investment		$418,215	$415,424	$412,632	$409,841	$407,049	$404,258	$401,466	$398,675	$395,884	$393,092	$390,301	$387,509	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$2,201	$2,187	$2,172	$2,157	$2,143	$2,128	$2,113	$2,099	$2,084	$2,069	$2,054	$2,040	$25,447
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$463	$460	$457	$454	$451	$448	$445	$442	$439	$436	$432	$429	$5,357
8. Investment Expenses														
a. Depreciation		$2,791	$2,791	$2,791	$2,791	$2,791	$2,791	$2,791	$2,791	$2,791	$2,791	$2,791	$2,791	$33,497
b. Amortization		$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)		$5,456	$5,438	$5,421	$5,403	$5,385	$5,367	$5,350	$5,332	$5,314	$5,296	$5,278	$5,261	$64,301

(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 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

FLORIDA POWER & LIGHT COMPANY
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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	$0	$0	$0	$0	$0	$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)	$215,367,615	$215,367,615	$215,367,615	$215,367,615	$215,367,615	$215,367,615	$215,367,615	$215,367,615	$215,367,615	$215,367,615	$215,367,615	$215,367,615	$215,367,615	
3a. Less: Accumulated Depreciation	$37,122,258	$37,953,773	$38,785,288	$39,616,803	$40,448,318	$41,279,833	$42,111,348	$42,942,863	$43,774,378	$44,605,893	$45,437,408	$46,268,923	$47,100,438	
4. CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5. Net Investment (Lines 2 - 3 + 4)	$178,245,357	$177,413,842	$176,582,327	$175,750,812	$174,919,297	$174,087,782	$173,256,267	$172,424,752	$171,593,237	$170,761,722	$169,930,207	$169,098,692	$168,267,177	
6. Average Net Investment		$177,829,599	$176,998,084	$176,166,569	$175,335,054	$174,503,539	$173,672,024	$172,840,509	$172,008,994	$171,177,479	$170,345,964	$169,514,449	$168,682,934	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$936,054	$931,677	$927,300	$922,923	$918,546	$914,169	$909,792	$905,416	$901,039	$896,662	$892,285	$887,908	$10,943,771
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$197,050	$196,129	$195,207	$194,286	$193,364	$192,443	$191,522	$190,600	$189,679	$188,758	$187,836	$186,915	$2,303,789
8. Investment Expenses														
a. Depreciation		$831,515	$831,515	$831,515	$831,515	$831,515	$831,515	$831,515	$831,515	$831,515	$831,515	$831,515	$831,515	$9,978,180
b. Amortization		$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)		$1,964,619	$1,959,321	$1,954,022	$1,948,724	$1,943,426	$1,938,127	$1,932,829	$1,927,531	$1,922,233	$1,916,934	$1,911,636	$1,906,338	$23,225,740

(a) Applicable to reserve salvage and removal cost.

(b) 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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning 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
50 - Steam Electric Effluent Guidelines Revised Rules														
Base														
1. Investments														
a. Expenditures/Additions		$0	$78,541	$78,541	$78,541	$78,541	$78,541	$78,541	$78,541	$78,541	$78,541	$78,541	$157,083	$942,496
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$942,496	$942,496
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	$942,496	
3a. Less: Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,096	
4. CWIP	$0	$0	$78,541	$157,083	$235,624	$314,165	$392,707	$471,248	$549,789	$628,330	$706,872	$785,413	$0	
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$78,541	$157,083	$235,624	$314,165	$392,707	$471,248	$549,789	$628,330	$706,872	$785,413	$941,400	
6. Average Net Investment		$0	$39,271	$117,812	$196,353	$274,895	$353,436	$431,977	$510,519	$589,060	$667,601	$746,142	$863,407	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$0	$207	$620	$1,034	$1,447	$1,860	$2,274	$2,687	$3,101	$3,514	$3,928	$4,545	$25,216
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$0	$44	$131	$218	$305	$392	$479	$566	$653	$740	$827	$957	$5,308
8. Investment Expenses														
a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,096	$1,096
b. Amortization		$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	$250	$751	$1,251	$1,752	$2,252	$2,752	$3,253	$3,753	$4,254	$4,754	$6,597	$31,620

(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 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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54 - Coal Combustion Residuals														
Base														
1. Investments														
a. Expenditures/Additions		$0	$1,127,074	$1,127,074	$1,127,074	$1,127,074	$1,127,074	$1,127,074	$1,127,074	$1,127,074	$1,127,075	$1,127,075	$2,254,149	$13,524,891
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$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)	$8,079,290	$8,079,290	$8,079,290	$8,079,290	$8,079,290	$8,079,290	$8,079,290	$8,079,290	$8,079,290	$8,079,290	$8,079,290	$8,079,290	$8,079,290	
3a. Less: Accumulated Depreciation	$16,327	$34,899	$53,471	$72,043	$90,615	$109,186	$127,758	$146,330	$164,902	$183,474	$202,045	$220,617	$239,189	
3b. Less: Capital Recovery Unamortized Balance	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	($56,167)	
4. CWIP	$62,257,361	$62,257,361	$63,384,435	$64,511,509	$65,638,583	$66,765,657	$67,892,731	$69,019,805	$70,146,879	$71,273,953	$72,401,028	$73,528,103	$75,782,252	
5. Net Investment (Lines 2 - 3 + 4)	$70,376,491	$70,357,919	$71,466,421	$72,574,923	$73,683,426	$74,791,928	$75,900,430	$77,008,932	$78,117,434	$79,225,937	$80,334,440	$81,442,943	$83,678,520	
6. Average Net Investment		$70,367,205	$70,912,170	$72,020,672	$73,129,175	$74,237,677	$75,346,179	$76,454,681	$77,563,183	$78,671,685	$79,780,188	$80,888,691	$82,560,732	
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes (c)(h)		$370,397	$373,265	$379,100	$384,935	$390,770	$396,605	$402,440	$408,275	$414,110	$419,944	$425,779	$434,581	$4,800,201
b. Debt Component (Line 6 x debt rate x 1/12) (d)(h)		$77,973	$78,577	$79,805	$81,033	$82,262	$83,490	$84,718	$85,946	$87,175	$88,403	$89,631	$91,484	$1,010,497
8. Investment Expenses														
a. Depreciation		$18,572	$18,572	$18,572	$18,572	$18,572	$18,572	$18,572	$18,572	$18,572	$18,572	$18,572	$18,572	$222,862
b. Amortization		$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)		$466,941	$470,414	$477,477	$484,540	$491,603	$498,667	$505,730	$512,793	$519,856	$526,919	$533,983	$544,637	$6,033,559

(a) Applicable to reserve salvage and removal cost.

(b) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 60-62.

(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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

(d) The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

(e) Applicable depreciation rate or rates. See Form 42-4P, pages 60-62.

(f) Applicable amortization period(s). See Form 42-4P, pages 60-62.

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

(h) For solar projects the return on investment calculation is comprised of two parts:
Return on 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. – Dec. 2019 period is 6.480% based on the May 2018 Earning Surveillance Report reflects a 10.55% return on equity.
Debt Component: the Debt Component for the Jan. – Dec. 2019 period is 1.670% based on the May 2018 Earning Surveillance Report.

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1. Working Capital Dr (Cr)														
a 158.100Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b 158.200Allowances Withheld	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c 182.300Other Regulatory Assets-Losses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d 254.900Other Regulatory Liabilities-Gains	($565)	($537)	($508)	($480)	($452)	($423)	($395)	($367)	($339)	($310)	($282)	($254)	($225)	
2. Total Working Capital	($565)	($537)	($508)	($480)	($452)	($423)	($395)	($367)	($339)	($310)	($282)	($254)	($225)	
3. Average Net Working Capital Balance		($551)	($522)	($494)	($466)	($438)	($409)	($381)	($353)	($324)	($296)	($268)	($240)	
4. Return on Average Net Working Capital Balance														
a Equity Component grossed up for taxes [a]		($3)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($1)	($1)	
b Debt Component (Line 6 x 1.6698% x 1/12) [b]		($1)	($1)	($1)	($1)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	
5. Total Return Component [c]		($4)	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($30)
6. Expense Dr (Cr)														
a 411.800Gains from Dispositions of Allowances		($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($276)
b 411.900Losses from Dispositions of Allowances		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c 509.000Allowance Expense		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7. Net Expense (Lines 6a+6b+6c) [d]		($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($23)	($276)
8 . Total System Recoverable Expenses (Lines 5+7)		($26)	($26)	($26)	($26)	($26)	($26)	($25)	($25)	($25)	($25)	($25)	($25)	($306)

[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. – Dec. 2019 period is 4.7156% based on the May 2018 Earning Surveillance Report and reflects a 10.55% return on equity.

[b] The Debt Component for the Jan. – Dec. 2019 period is 1.3297% based on the May 2018 Earning Surveillance Report.

[c] Line 5 is reported on Capital Schedule 3P-1.

[d] Line 7 is reported on O&M Schedule 2P-1.

2019 Depreciation Schedule **FORM 42-4P**

Project	Class ID	Plant	Unit	Utility	Depr. Rate / Amort. Period	Balance as of Dec-18	Balance as of Dec-19
002-LOW NOX BURNER TECHNOLOGY	**02 - Steam Generation Plant**	Turkey Pt	**Turkey Pt U1**	31200	CRS	-	-
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**	31650	5-Year	58,207	-
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	Martin	**Martin Comm**	31670	7-Year	66,897	66,897
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	Martin	**Martin Comm U1&2**	31200	4.45%	31,632	31,632
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	Martin	**Martin U1**	31100	2.68%	36,811	36,811
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	Martin	**Martin U1**	31200	4.53%	399,323	399,323
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	Martin	**Martin U2**	31100	2.39%	36,845	36,845
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	Martin	**Martin U2**	31200	4.64%	335,746	335,746
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	Scherer	**Scherer U4**	31200	2.79%	515,653	515,653
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	St Johns River Power Plant	**SJRPP - Comm**	31100	CRS	-	-
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	St Johns River Power Plant	**SJRPP U1**	31200	CRS	-	-
003-CONTINUOUS EMISSION MONITORING	**02 - Steam Generation Plant**	St Johns River Power Plant	**SJRPP U2**	31200	CRS	-	-
003-CONTINUOUS EMISSION MONITORING	**05 - Other Generation Plant**	Ft Lauderdale	**FtLauderdale Comm**	34100	2.20%	58,860	58,860
003-CONTINUOUS EMISSION MONITORING	**05 - Other Generation Plant**	Ft Lauderdale	**FtLauderdale Comm**	34500	1.60%	34,502	34,502
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 Lauderdale	**FtLauderdale U4**	34300	4.11%	438,897	438,897
003-CONTINUOUS EMISSION MONITORING	**05 - Other Generation Plant**	Ft Lauderdale	**FtLauderdale U5**	34300	5.00%	556,425	556,425
003-CONTINUOUS EMISSION MONITORING	**05 - Other Generation Plant**	Ft Myers	**FtMyers U2**	34100	0.00%	-	-
003-CONTINUOUS EMISSION MONITORING	**05 - Other Generation Plant**	Ft Myers	**FtMyers U2**	34300	3.46%	368,561	368,561
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%	727,809	727,809
003-CONTINUOUS EMISSION MONITORING	**05 - Other Generation Plant**	Martin	**Martin U4**	34300	3.92%	720,022	720,022
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						**6,293,477**	**6,235,270**
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%	771,705	771,705
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	**02 - Steam Generation Plant**	Martin	**Martin Comm**	31200	4.45%	94,209	94,209
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	**02 - Steam Generation Plant**	Martin	**Martin Comm U1&2**	31100	2.52%	824,065	824,065
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	**02 - Steam Generation Plant**	Martin	**Martin U1**	31100	2.68%	261,417	261,417
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	**02 - Steam Generation Plant**	Martin	**Martin U2**	31100	2.39%	85,078	85,078
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	**02 - Steam Generation Plant**	St Johns River Power Plant	**SJRPP - Comm**	31100	CRS	-	-
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS	**02 - Steam Generation Plant**	St Johns River Power Plant	**SJRPP - Comm**	31200	CRS	-	-
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 SC Peaker**	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%	7,174,603	7,174,603
005-MAINTENANCE OF ABOVE GROUND FUEL TANKS Total						**14,819,595**	**14,819,595**
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 Comm**	31670	7-Year	21,347	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	**02 - Steam Generation Plant**	Martin	**Martin Comm**	31600	3.79%	23,107	23,107
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	**02 - Steam Generation Plant**	Martin	**Martin Comm**	31650	5-Year	181,542	256,542
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	**02 - Steam Generation Plant**	Martin	**Martin Comm**	31670	7-Year	298,813	298,813
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT	**05 - Other Generation Plant**	Ft Lauderdale	**FtLauderdale Comm**	34100	2.20%	364,027	364,027
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	**08 - General Plant**	General Plant	**General Plant**	39190	33.33%	-	-
008-OIL SPILL CLEANUP/RESPONSE EQUIPMENT Total						**959,049**	**1,012,702**
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	2.07%	689	689
012-SCHERER DISCHARGE PIPELINE Total						**854,324**	**854,324**
020-WASTEWATER/STORMWATER DISCH ELIMINATION	**02 - Steam Generation Plant**	Martin	**Martin U1**	31200	4.53%	367,906	367,906
020-WASTEWATER/STORMWATER DISCH ELIMINATION	**02 - Steam Generation Plant**	Martin	**Martin U2**	31200	4.64%	403,671	403,671
020-WASTEWATER/STORMWATER DISCH ELIMINATION Total						**771,577**	**771,577**
021-ST.LUCIE TURTLE NETS	**03 - Nuclear Generation Plant**	St Lucie	**StLucie Comm**	32100	2.25%	6,909,559	6,909,559
021-ST.LUCIE TURTLE NETS Total						**6,909,559**	**6,909,559**
022-PIPELINE INTEGRITY MANAGEMENT	**02 - Steam Generation Plant**	Manatee	**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**

2019 Depreciation Schedule

FORM 42-4P

Project	Class ID	Plant	Unit	Utility	Depr. Rate / Amort. Period	Balance as of Dec-18	Balance as of Dec-19
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	1,549,762
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%	574,162	574,162
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin	Martin Comm	31500	3.57%	34,755	34,755
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	02 - Steam Generation Plant	Martin	Martin Comm U1&2	31100	2.52%	-	1,329,538
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%	988,529	988,529
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	03 - Nuclear Generation Plant	Turkey Pt	Turkey Pt Comm	32570	7-Year	243,990	243,990
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
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 Lauderdale	FtLauderdale U4	34300	4.11%	-	250,000
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	34300	3.46%	49,727	302,652
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Ft Myers	FtMyers U3 SC Peaker	34500	3.40%	12,430	12,430
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	05 - Other Generation Plant	Martin	Martin Comm U3&4	34100	2.24%	523,498	523,498
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	2,978,283
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	Radial	35200	1.70%	6,946	6,946
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35200	1.70%	1,207,640	1,287,640
023-SPILL PREVENTION CLEAN-UP & COUNTERMEASURES	06 - Transmission Plant - Electric	Transmission	Transmission Plant - Electric	35300	2.04%	3,786,256	3,936,256
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%	3,303,417	3,330,917
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						**20,463,782**	**24,320,235**
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee Comm	31200	7.62%	-	310,770
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee U1	31200	4.64%	16,342,411	16,342,411
024-GAS REBURN	02 - Steam Generation Plant	Manatee	Manatee U2	31200	4.99%	15,315,595	15,315,595
024-GAS REBURN Total						**31,658,006**	**31,968,776**
026-UST REPLACEMENT/REMOVAL	08 - General Plant	General Plant	General Plant	39000	1.50%	115,447	115,447
026-UST REPLACEMENT/REMOVAL Total						**115,446.69**	**115,447**
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	Cape Canaveral	CapeCana Comm CC	34100	2.69%	767,152	767,152
028-CWA 316B PHASE II RULE	05 - Other Generation Plant	Cape Canaveral	CapeCanaveral Comm	34100	2.69%	-	2,023,400
028-CWA 316B PHASE II RULE Total						**767,152.37**	**2,790,552**
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%	20,461,529	20,461,529
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	Martin	Martin Comm	31400	3.48%	287,258	287,258
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin Comm U1&2	31200	4.45%	518,275	518,275
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin U1	31200	4.53%	19,504,077	19,504,077
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin U1	31400	3.35%	7,499,710	7,499,710
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin U2	31200	4.64%	20,224,580	20,224,580
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Martin	Martin U2	31400	4.79%	7,477,120	7,477,120
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	Scherer	Scherer Comm U3&4	31200	2.32%	406,783	406,783
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	256,829,346
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	12,775	268
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U1	31200	CRS	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U1	31500	CRS	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U1	31600	CRS	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U2	31200	CRS	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U2	31500	CRS	-	-
031-CLEAN AIR INTERSTATE RULE-CAIR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U2	31600	CRS	-	-
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						**469,868,352**	**472,209,255**
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%	109,897,484	110,329,098
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U1	31200	CRS	-	-
033-CLEAN AIR MERCURY RULE-CAMR	02 - Steam Generation Plant	St Johns River Power Plant	SJRPP U2	31200	CRS	-	-
033-CLEAN AIR MERCURY RULE-CAMR Total						**108,663,447.52**	**109,095,062**
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE	03 - Nuclear Generation Plant	St Lucie	StLucie Comm	32100	2.25%	-	4,500,614
034-PSL COOLING WATER SYSTEM INSPECTION & MAINTENANCE Total						**-**	**4,500,614**
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						**235,391.32**	**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	115,292,583
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	34600	3.30%	-	65,496
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34630	3-Year	8,469	8,469
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34650	5-Year	51,031	51,031
037-DE SOTO SOLAR PROJECT	05 - Other Generation Plant	Desoto	Desoto Solar	34670	7-Year	151,580	151,580
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						**153,522,789**	**153,588,284**

FLORIDA POWER & LIGHT
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE PROJECTION AMOUNT

2019 Depreciation Schedule

FORM 42-4P

Project	Class ID	Plant	Unit	Utility	Depr. Rate / Amort. Period	Balance as of Dec-18	Balance as of Dec-19
038-SPACE COAST SOLAR PROJECT	**01 - Intangible Plant**	Intangible Plant	**Intangible Plant**	30300	30-year	6,359,027	6,359,027
038-SPACE COAST SOLAR PROJECT	**05 - Other Generation Plant**	Space Coast	**Space Coast Solar**	34100	3.45%	3,889,496	3,889,496
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	35,202
038-SPACE COAST SOLAR PROJECT	**05 - Other Generation Plant**	Space Coast	**Space Coast Solar**	34670	7-Year	-	-
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						**70,587,644**	**70,587,644**
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%	20,745,276	20,745,276
039-MARTIN SOLAR PROJECT	**05 - Other Generation Plant**	Martin Solar	**Martin Solar**	34300	2.88%	398,071,563	400,200,334
039-MARTIN SOLAR PROJECT	**05 - Other Generation Plant**	Martin Solar	**Martin Solar**	34500	2.99%	4,122,852	4,122,852
039-MARTIN SOLAR PROJECT	**05 - Other Generation Plant**	Martin Solar	**Martin Solar**	34600	2.85%	1,299	1,299
039-MARTIN SOLAR PROJECT	**05 - Other Generation Plant**	Martin Solar	**Martin Solar**	34650	5-Year	-	-
039-MARTIN SOLAR PROJECT	**05 - Other Generation Plant**	Martin Solar	**Martin Solar**	34670	7-Year	129,522	129,522
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	**08 - General Plant**	General Plant	**General Plant**	39420	7-Year	-	-
039-MARTIN SOLAR PROJECT	**08 - General Plant**	General Plant	**General Plant**	39720	7-Year	-	-
039-MARTIN SOLAR PROJECT Total						**425,318,258**	**427,447,029**
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**	Ft Lauderdale	**Dania Beach Unit 7**	34300	44-Month	6,881,474	6,881,474
041-PRV MANATEE HEATING SYSTEM	**05 - Other Generation Plant**	Ft Myers	**FtMyers U2**	34300	0.00%	-	5,609,682
041-PRV MANATEE HEATING SYSTEM	**06 - Transmission Plant - Electric**	Transmission	**Transmission Plant - Electric**	35300	0.00%	276,404	276,404
041-PRV MANATEE HEATING SYSTEM	**07 - Distribution Plant - Electric**	Distribution	**Mass Distribution Plant**	36100	0.00%	73,267	73,267
041-PRV MANATEE HEATING SYSTEM	**07 - Distribution Plant - Electric**	Distribution	**Mass Distribution Plant**	36200	0.00%	471,542	471,542
041-PRV MANATEE HEATING SYSTEM	**07 - Distribution Plant - Electric**	Distribution	**Mass Distribution Plant**	36500	0.00%	307,599	307,599
041-PRV MANATEE HEATING SYSTEM	**07 - Distribution Plant - Electric**	Distribution	**Mass Distribution Plant**	36660	0.00%	221,326	221,326
041-PRV MANATEE HEATING SYSTEM	**07 - Distribution Plant - Electric**	Distribution	**Mass Distribution Plant**	36760	0.00%	168,995	168,995
041-PRV MANATEE HEATING SYSTEM	**07 - Distribution Plant - Electric**	Distribution	**Mass Distribution Plant**	36910	0.00%	607	607
041-PRV MANATEE HEATING SYSTEM	**07 - Distribution Plant - Electric**	Distribution	**Mass Distribution Plant**	36420	0.00%	-	-
041-PRV MANATEE HEATING SYSTEM	**07 - Distribution Plant - Electric**	Distribution	**Mass Distribution Plant**	36410	0.00%	137,247	137,247
041-PRV MANATEE HEATING SYSTEM Total						**12,580,920**	**18,190,602**
042-PTN COOLING CANAL MONITORING SYS	**03 - Nuclear Generation Plant**	Turkey Pt	**Turkey Pt Comm**	32100	3.13%	44,687,786	61,017,195
042-PTN COOLING CANAL MONITORING SYS	**05 - Other Generation Plant**	Turkey Pt	**Turkey Pt U5**	34100	2.33%	3,492,353	3,492,353
042-PTN COOLING CANAL MONITORING SYS Total						**48,180,139**	**64,509,548**
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						**164,718.55**	**164,719**
045-800 MW UNIT ESP PROJECT	**02 - Steam Generation Plant**	Manatee	**Manatee Comm**	31200	7.62%	1,059,420	1,059,420
045-800 MW UNIT ESP PROJECT	**02 - Steam Generation Plant**	Manatee	**Manatee U1**	31200	4.64%	44,989,219	44,989,219
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%	51,910,750	51,910,750
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%	1,071,311	1,071,311
045-800 MW UNIT ESP PROJECT	**02 - Steam Generation Plant**	Martin	**Martin U1**	31200	4.53%	47,136,708	47,136,708
045-800 MW UNIT ESP PROJECT	**02 - Steam Generation Plant**	Martin	**Martin U1**	31500	3.12%	4,322,420	4,322,420
045-800 MW UNIT ESP PROJECT	**02 - Steam Generation Plant**	Martin	**Martin U1**	31600	3.81%	1,012,007	1,012,007
045-800 MW UNIT ESP PROJECT	**02 - Steam Generation Plant**	Martin	**Martin U2**	31200	4.64%	48,445,547	48,445,547
045-800 MW UNIT ESP PROJECT	**02 - Steam Generation Plant**	Martin	**Martin U2**	31500	3.56%	4,449,270	4,449,270
045-800 MW UNIT ESP PROJECT	**02 - Steam Generation Plant**	Martin	**Martin U2**	31600	4.31%	1,070,760	1,070,760
045-800 MW UNIT ESP PROJECT Total						**215,807,202**	**215,807,202**
050-Steam Electric Effluent Guidelines Revised Rules	**02 - Steam Generation Plant**	Scherer	**Scherer U4**	31200	2.79%	-	942,496
050-Steam Electric Effluent Guidelines Revised Rules Total						**-**	**942,496**
054-Coal Combustion Residuals	**02 - Steam Generation Plant**	Scherer	**Scherer Comm**	31100	1.51%	199,237	199,237
054-Coal Combustion Residuals	**02 - Steam Generation Plant**	Scherer	**Scherer U4**	31200	2.79%	7,880,053	7,880,053
054-Coal Combustion Residuals	**02 - Steam Generation Plant**	St Johns River Power Plant	**SJRPP - Comm**	31100	CRS	-	-
054-Coal Combustion Residuals Total						**8,079,290**	**8,079,290**
Grand Total						**1,617,098,537**	**1,655,633,591**

FORM: 42-5P

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 Florida Statute 403.0872 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 within the State of Florida, as well as Plant Scherer's Unit 4 located in Juliette, Georgia of which FPL owns a 76.36% share. 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 on a monthly basis for submittal to the Georgia Environmental Protection Department by the operating agent.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

O&M - Previous year's air operating permit fees for Florida facilities were calculated in the first quarter of 2018 utilizing 2017 air operating information and paid to DEP. Permit fees for FPL's ownership share of Scherer Unit 4 were paid monthly.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $287,797, which is $25,018 or 10% higher than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $233,257.

FORM: 42-5P

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 attainment of 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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

Capital - Project revenue requirements are estimated to be $62,269, which is $245 or 0.4% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

Capital - Estimated project revenue requirements for the projection period are $59,135.

FORM: 42-5P

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 have installed CEMS to comply with these requirements. Operation and maintenance of CEMS in accordance with the provisions of 40 CFR Part 75 is an ongoing activity, which follows the FPL CEMS Quality Assurance ("QA") Program Manual approved by the Environmental Protection Agency ("EPA").

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

Operation and maintenance 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. Relative accuracy stack tests and linearity tests continue to be performed as scheduled for quality assurance and as needed for diagnostic or recertification requirements. Quality assurance maintenance continues to be performed on the analyzers to meet reliability and availability requirements. CEMS required parts are purchased as needed for repairs and/or preventative maintenance. Equipment having met end of life is replaced as determined in the QA Manual. CEMS analyzer calibration gases, that ensure accuracy of the measurements, are required to be used daily and are purchased as needed. Analysis of fuel oil for sulfur content, heat of combustion and carbon must be periodically performed per the requirements of 40 CFR Part 75, Appendix D. 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. Maintenance of the software also ensures compliance with current rules or regulations and changes made by EPA, state and local agencies. Training on the operation and maintenance of the system, as well as rule/regulation changes continue as needed.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $337,938, which is $35,807 or 10% lower than previously projected.

Capital - Project revenue requirements are estimated to be $596,293, which is $81,100 or 12.0% lower than previously projected. The variance is primarily related to the replacement of a CEMS server at the Sanford Plant in 2017, which was originally projected to occur in 2018. In addition, the Martin Plant NOx analyzers and CEMS servers on Units 1 and 2 were removed due to dismantlement. These decreases were partially offset by higher than projected costs of NOx analyzers at Martin Units 3 and 4.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $544,646.

Capital - Estimated project revenue requirements for the projection period are $588,862.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Clean Closure Equivalency

Project No. 4

Project Description:

In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed Closure Equivalency Determinations for nine FPL power plants to demonstrate to EPA that no hazardous waste or hazardous constituents remain in the soil or water beneath the basins, which had been used in the past to treat corrosive hazardous waste. The basins, which are still operational as part of the wastewater treatment systems at these plants, are no longer used to treat hazardous waste.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

Project costs are estimated to be $0.

Project Projections:

(January 1, 2019 to December 31, 2019)

Estimated project revenue requirements for the projection period are $0. This project is complete and fully recovered. This report will be removed from future project progress reports.

FORM: 42-5P

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 DEP for tanks that are in operation.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. External inspection is scheduled this year for one of the tanks at Manatee Terminal. Additionally, full coating projects were completed for two Martin Plant tanks earlier this year. The repairs of the Port Everglades 901/902 tanks are in progress, as well as the conversions of the Port Everglades 903/904 tanks.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project expenditures are estimated to be $699,377, which is $1.1 million or 61% lower than previously projected. The variance is primarily due to the planned retirement of Martin Units 1 and 2 by the end of 2018, which eliminated the need for project activities associated with those units that were included in the original 2018 projections.

Capital - Project revenue requirements are estimated to be $1,672,922, which is $91,143 or 5.8% higher than previously projected.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $467,402.

Capital - Estimated project revenue requirements for the projection period are $1,633,235.

FORM: 42-5P

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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

Capital - Project revenue requirements are estimated to be $1,782, which is $1 or 0.1% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

Capital - Estimated project revenue requirements for the projection period are $1,659.

FORM: 42-5P

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 could reasonably 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 the 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, 2018 to December 31, 2018)

Facility Response Plan updates continue to be performed for all sites as required. Routine maintenance of all oil spill equipment has continued throughout the year as well as training and planned oil spill drills.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $273,045, which is $269 or 0.1% lower than previously projected.

Capital - Project revenue requirements are estimated to be $152,108, which is $2,863 or 1.8% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

O&M - Estimated project costs for the projection period are $284,248.

Capital - Estimated project revenue requirements for the projection period are $169,985.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Storm Water Runoff

Project No. 10

Project Description:

The National Pollutant Discharge Elimination System ("NPDES") permit, Permit No. FL0002206 for the St. Lucie plant, issued by 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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

Capital - Project revenue requirements are estimated to be $6,513, which is $39 or 0.6% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

Capital - Estimated project revenue requirements for the projection period are $6,270.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Scherer Discharge Pipeline

Project No. 12

Project Description:

On March 16, 1992, pursuant to the provisions of the Georgia Water Control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated thereunder, the Georgia Department of Natural Resources ("the Department") issued the National Pollutant Discharge Elimination System ("NPDES") permit for Plant Scherer to Georgia Power Company. 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 Company was required to construct an alternate outfall to redirect certain wastewater discharges to the Ocmulgee River. Pursuant to the ownership agreement with Georgia Power Company 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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

Capital - Project revenue requirements are estimated to be $35,530, which is $205 or 0.6% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

Capital - Estimated project revenue requirements for the projection period are $34,152.

FORM: 42-5P

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 National Pollution Discharge Elimination System ("NPDES"). These fees implement the Florida legislature's intent that DEP's costs for administering the NPDES program be borne by the regulated parties, as applicable.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

The NPDES permit fees were paid to DEP for applicable power generation and nuclear plants.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $69,200, which is $200 or 0.3% higher than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

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

FORM: 42-5P

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. In order to comply with Florida Administrative Code 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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $0, which is $5,000 or 100% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

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

FORM: 42-5P

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 department. 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, 2018 to December 31, 2018)

Leak repair and regasketing work continues as needed on affected equipment identified during inspections. A mobile transformer has been utilized at two locations to alleviate energy load problems in critical substations in order to repair and regasket leaking transformers. The arsenic remediation work continues to be addressed at four substations where historical impacts have been identified.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M -

19a. Project costs are estimated to be $2,619,748, which is $55,522 or 2.1% lower than previously projected.

19b. Project costs are estimated to be $1,066,231, which is $78,291 or 7.9% higher than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

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

19a. $2,675,270

19b. $987,940

FORM: 42-5P

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, 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 and Cutler plants' wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan 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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

Capital - Project revenue requirements are estimated to be $77,613, which is $425 or 0.5% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

Capital - Estimated project revenue requirements for the projection period are $74,467.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Turtle Net

Project No. 21

Project Description:

The Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on March 24, 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, 2018 to December 31, 2018)

Inspections and cleaning were performed to remove algae and jellyfish buildup that occurred on the turtle net. In early 2018 the 5-inch primary barrier net was replaced due to damage and impacts from Hurricane Irma.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $103,420, which is $6,580 or 6.0% lower than previously projected.

Capital - Project revenue requirements are estimated to be $740,606, which is $5,961 or 0.8% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $110,000.

Capital - Estimated project revenue requirements for the projection period are $722,690.

FORM: 42-5P

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, 2018 to December 31, 2018)

Cathodic Protection Surveys were completed for the following:

- Martin Terminal 24" & 30" oil pipeline to the Port of Palm Beach and the
- 18" fuel oil pipeline to the Martin Plant; 24" natural gas pipeline and compressor station piping from terminal to Riviera plant. Manatee Terminal 30" & 16" fuel oil piping to Manatee plant.
- Sanford Plant natural gas piping from meter yard to Units 4 & 5.

Public outreach meetings with contractors (excavators) and first responders are planned to begin in September and continue through the end of the year in advance of planned pipeline work. Preliminary work has begun on assessing Manatee pipeline depth of cover over piping, but no related field execution has been initiated.

Project Costs:

(January 1, 2018 to December 31, 2018)

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

O&M - Project expenditures are estimated to be $80,476, which is $505,524 or 86.3% lower than previously projected. The variance is primarily due to the planned retirement of Martin Units 1 and 2 by the end of 2018, which eliminated the need for project activities associated with those units that were included in the original 2018 projections.

Capital - Project revenue requirements are estimated to be $269,328, which is $33,237 or 11.0% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $181,408.

Capital - Estimated project revenue requirements for the projection period are $261,500.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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

Project No. 23

Project Description:

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, 2018 to December 31, 2018)

FPL routinely reviews and updates the Facility Response Plans 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 the addition/modification of fuel gas metering stations at Martin, the addition of fuel efficient combustion turbine peaking units at Fort Lauderdale and the removal of obsolete gas turbine peaking units at Port Everglades.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $890,752, which is $44,612 or 5.3% higher than previously projected.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Capital - Project revenue requirements are estimated to be $2,135,454, which is $189,192 or 8.1% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $802,138.

Capital - Estimated project revenue requirements for the projection period are $2,538,376.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Plant Reburn

Project No. 24

Project Description:

This project involves installation of reburn technology in Manatee Units 1 and 2. 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. Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone where a portion of the NOx formed from combustion is converted back into elemental nitrogen.

In response to concerns about local ground level ozone during the 1996-97 time period, FPL invested considerable effort evaluating the Manatee Units for the application of reburn technology. Installation of reburn technology for Manatee Units 1 and 2 resulted in a reduction in NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, and pollution reduction or removal equipment. FPL determined that reburn technology was the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2 to reduce impacts to local ozone air quality impacts that DEP had required FPL to achieve.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

The site has completed maintenance during the Unit 2 overhaul for the burner assemblies, burner swirler, and damper inspections on the system.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $116,892, which is $9,084 or 7.2% lower than previously projected.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Capital - Project revenue requirements are estimated to be $3,150,126, which is $13,724 or 0.4% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $159,939.

Capital - Estimated project revenue requirements for the projection period are $3,042,624.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: 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. Underground Storage Tank ("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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

Capital - Project revenue requirements are estimated to be $6,764, which is $51 or 0.8% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Capital - Estimated project revenue requirements for the projection period are $6,580.

FORM: 42-5P

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, 2018 to December 31, 2018)

For 2018, 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, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $142,896, which is $13,104 or 8.4% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $156,000.

FORM: 42-5P

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, 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. DEP adopted and is implementing the 316(b) Rule in its entirety, effective June 24, 2015, at the following FPL facilities: Cape Canaveral, Ft. Myers, Lauderdale, Riviera, Sanford, Martin, Manatee and St. Lucie Plants, as well as SJRPP. Plant Scherer is also regulated by the 316(b) Rule through the Georgia Environmental Protection Division.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

In 2018, 316(b) compliance information was submitted for the Sanford, Martin and Manatee and Scherer plants as part of the permit renewal process. Entrainment sampling was completed at the Ft. Lauderdale Plant, Riviera Beach Energy Center, Port Everglades Energy Center, the Ft. Myers Plant, and Cape Canaveral Energy Center and was in progress at the St. Lucie Plant. Also, 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.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

At the Cape Canaveral Energy Center, the new horseshoe crab deterrent wall (installed October 2017) has reduced the impingement of horseshoe crabs in 2018 by more than 95% compared to the time period before installation of the wall.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $1,441,646, which is $84,469 or 5.5% lower than previously projected.

Capital - Project revenue requirements are estimated to be $78,782, which is $125,813 or 61.5% lower than previously projected. The variance is primarily attributed to lower than estimated costs for construction of the horseshoe crab barrier in 2017, which impacted the beginning balance in 2018.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $1,408,067.

Capital - Estimated project revenue requirements for the projection period are $143,340.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SCR Consumables

Project No. 29

Project Description:

The Manatee Unit 3 and Martin 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 Selective Catalytic Reduction systems ("SCR") for the control of NOx emissions. DEP made the determination that the SCR system is considered Best Available Control Technology ("BACT") for these types of units, with concurrence from 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, 2018 to December 31, 2018)

The Manatee site has completed its annual training as required.

In 2018, the Martin Plant Unit 8 SCR system will complete a three year inspection of 8D Heat Recovery System Generators ("HRSG"). Annual inspections will also be completed on 8A, 8B, and 8C HRSG. Throughout the year, anhydrous ammonia and calibration gases will be purchased as needed.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $532,480, which is $184,612 or 25.7% lower than previously projected. The variance is primarily related to lower ammonia consumption associated with a reduction in unit operations. In addition, costs for planned outage work, which include SCR annual inspections on Martin Units 8A, B & C, SCR 3-year inspection on Martin Unit 8D, and piping inspections in the fall of 2018 at the Martin site are now projected to be less than originally estimated.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $551,133.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Hydrobiological Monitoring Program ("HBMP")

Project No. 30

Project Description:

HBMP was required by the Southwest Florida Water Management District ("SWFWMD") in the Conditions of Certification for construction of Manatee Unit 3. The HBMP involved the data collection of river chemistry, flow and vegetation conditions to demonstrate that the plant's withdrawals would not impact the environment in and along the Little Manatee River. The Hydrobiological Monitoring Program was a 10-year study, which started in 2003 during the construction phase of Unit 3 and was completed in 2013. Correspondence submitted to the SWFWMD in 2014 requested discontinuance of the Program. SWFWMD responded to FPL on July 20, 2016, and stated they had no objection to the discontinuance of the Program.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

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

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $0. This project is complete and fully recovered and this report will be removed from future project progress reports.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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

Project No. 31

Project Description:

In response to 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 Units 1 and 2, Manatee Units 1 and 2), the construction and operation of SCRs on 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 EPA's CAIR requirements, Georgia Environmental Protection Division ("EPD") promulgated the GA Multi-Pollutant rule also requiring installation of an SCR and a Scrubber on Scherer Unit 4.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

2017 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. The Scherer project O&M 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. SJRPP was retired January 5, 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $4,797,154 which is $92,407 or 1.9% lower than previously projected.

Capital - Project revenue requirements are estimated to be $48,156,194, which is $596,317 or 1.2% lower than previously projected.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $3,829,248.

Capital - Estimated project revenue requirements for the projection period are $46,792,403.

FORM: 42-5P

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 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, 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 units at SJRPP and Scherer are 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 EPA could ignore costs when deciding to regulate power plants. While the court has not yet issued an opinion on the validity of MATS, the rule is final and FPL must comply with the requirements until it is revoked or reissued.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

For Scherer, operation for the baghouse and sorbent injection system continues per the requirements of the State of Georgia Multi Pollutant Rule and MATS. SJRPP was retired on January 5, 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $2,395,698, which is on target for 2018.

Capital - Project revenue requirements are estimated to be $9,606,375, which is $198,481 or 2.0% lower than previously projected.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $2,701,008.

Capital - Estimated project revenue requirements for the projection period are $9,386,202.

FORM: 42-5P

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 ESA. 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, 2018 to December 31, 2018)

A prototype of the excluder devise has been constructed and testing was conducted in accordance with the BO. Test results of the proposed configuration showed possible injury to turtles. The testing associated with the proposed turtle barrier has been suspended due to comments received from NMFS and the Florida Fish and Wildlife Conservation Commission ("FWC").

Project Costs:

(January 1, 2018 to December 31, 2018)

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

Capital - Project revenue requirements are estimated to be $347,643, which is $101,418 or 22.6% lower than previously projected. The variance is primarily due to suspension of activity associated with the proposed turtle barrier pending receipt of comments from NMFS and FWC on possible alternatives after test results of the proposed configuration of the turtle barrier showed possible injury to turtles.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2019 to December 31, 2019)

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

Capital - Estimated project revenue requirements for the projection period are $463,851.

FORM: 42-5P

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 DEP's rules for drinking water systems. 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, 2018 to December 31, 2018)

FPL performed monthly maintenance and cleaning of nano-filter membranes related to the operation of the potable water system. The filter and tank are being replaced this year as part of a capital upgrade, so there is no routine carbon replacement planned for 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $36,715, which is $911 or 2.5% higher than previously projected.

Capital - Project revenue requirements are estimated to be $20,466, which is $148 or 0.7% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

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

Capital - Estimated project revenue requirements for the projection period are $19,863.

FORM: 42-5P

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. This project will construct a LLW storage facility for class B and C radioactive waste at the St. Lucie . Turkey Point plants ; however, the Turkey Point project will start later than the St. Lucie project since Turkey Point has limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at the St. Lucie and Turkey Point plants is to ensure construction of a LLW storage facility 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 will 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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

Capital - Project revenue requirements are estimated to be $1,690,444, which is $12,305 or 0.7% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

Capital - Estimated project revenue requirements for the projection period are $1,641,273.

FORM: 42-5P

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, 2018 to December 31, 2018)

For January through June 2018, Desoto Solar's net energy production was 24,588 MWh. Several field walk downs were performed this year to identify failing components that will be replaced during the remainder of this year. This will ensure improved efficiency to current performance. Site personnel continue to perform required maintenance activities including replacement of components as necessary.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $575,861, which is $33,868 or 5.6% lower than previously projected.

Capital - Project revenue requirements are estimated to be $12,719,862, which is $67,259 or 0.5% lower than previously projected.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $499,789.

Capital - Estimated project revenue requirements for the projection period are $12,209,466.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Space Coast Next Generation Solar Energy Center**

Project No. 38

Project Description:

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

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

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

For January through the end of June, 2018, net energy production at Space Coast Solar was 9,124 MWh. Work is being conducted to improve meteorological stations and DC field performance measurement to improve remote monitoring of the DC field. The KSC site operated well from January through May, with the malfunction of an inverter and communications in June 2018 resulted in lower than anticipated generation from the KSC site for that month. This resulted in measured net energy production of 659 MWh. 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.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $391,873, which is $12,270 or 3.2% higher than previously projected.

Capital - Project revenue requirements are estimated to be $5,903,927, which is $40,925 or 0.7% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $319,363.

Capital - Estimated project revenue requirements for the projection period are $5,671,978.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Next Generation Solar Energy Center

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, 2018 to December 31, 2018)

Martin Solar 2018 accomplishments include: routine repairs to solar loops, engineering and construction of modified array support pedestals and a comprehensive planned outage on the HTF system. During the outage in the fall of 2018 we will be overhauling critical feed water control valves and also perform inspections of the heat transfer fluid vessels.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $4,325,647, which is $837,854 or 24.0% higher than previously projected. The variance is primarily due to the acceleration of the maintenance outage at Unit 8 from 2019 to the fourth quarter of 2018, which also accelerated the outage work.

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FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Capital - Project revenue requirements are estimated to be $35,389,515, which is $273,666 or 0.8% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $3,346,966.

Capital - Estimated project revenue requirements for the projection period are $34,282,678.

FORM: 42-5P

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 EPA's policies that require reductions in emissions of GHGs from electric generating units and mandatory reporting of GHG emissions. 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. EPA's performance standards for reductions of GHG emissions have been stayed by the U.S. Supreme Court, and until EPA revises its rules, FPL does not have any required GHG emission reductions.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

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

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - There are no projected costs.

FORM: 42-5P

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. In order to comply with the legal requirement during modernizations, FPL undertook the design, engineering, purchase, and installation of MTHS for Cape Canaveral, Riviera and Port Everglades. Likewise, FPL is planning to implement a modernization project at Lauderdale for the construction of the Dania Beach Energy Center which will also require a MTHS during the modernization process.

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 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 operation in the future.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

In September 2017 the modernization of Fort Lauderdale began. One of the first items addressed was the installation of a MTHS so it could be in place for the 2018-19 manatee season and beyond.

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FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

In addition, Fort Myers started construction of a permanent MTHS, which is expected to be completed by December 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $663,434, which is $14,666 or 2.2% lower than previously projected.

Capital - Project revenue requirements are estimated to be $478,899, which is $210,440 or 30.5% lower than previously projected. The variance is primarily due to the delay of capital spend and in-service dates for the Dania Beach MTHS, which resulted in a reduction in forecasted debt and equity return and depreciation expense. This decrease is partially offset by the addition of the Ft. Myers Plant MTHS as discussed in FPL's April 2, 2018 testimony.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $215,900.

Capital - Estimated project revenue requirements for the projection period are $2,708,761.

FORM: 42-5P

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 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 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, 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 identifies a series of potential measures that FPL could include in the Salinity Management Plan ("SMP") that FPL must file with DEP outlining how it will do so. 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, 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 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 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, 2018 to December 31, 2018)

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FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

FPL continues to move forward with compliance and implementation of actions associated with activities required under the CO, CA and CAA. On May 9, 2018 FPL received a Section 404 permit from the U.S. Army Corp of Engineers for the restoration of the Turning Basin and Turtle Point Canal, two deep external artificial channels adjacent to the CCS. The final permit for the restoration work is expected later this year. On May 15, 2018, FPL began operation of the recovery well system ("RWS") consisting of 10 extraction wells required by the CO and CA. The RWS will extract 15 million gallons per day of hypersaline groundwater from the Biscayne aquifer and safely dispose it in an underground injection control ("UIC") well. Since FPL began extracting the hypersaline plume using an interim extraction system in the fall of 2016, FPL has removed approximately 3,800 million pounds of salt from the Biscayne Aquifer. Prior to operation of the RWS, FPL completed a baseline controlled source electromagnetic survey required by the CO and CA. This survey will provide a three dimensional view of the hypersaline plume and aid in assessing the extraction of the hypersaline plume. Pursuant to the CO, on June 20, 2018 FPL completed an analysis that seeks to allocate relative contributions of other entities or factors to the movement of the saltwater interface. This analysis was completed using the variable density three dimensional groundwater model developed under the CA, with input from DEP and other agencies.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project expenditures are $28,268,375, which is $9,463,456 or 50.3% higher than previously projected. The variance is primarily due to the deferral of certain activities from 2017 to 2018, as discussed in FPL witness Michael W. Sole's testimony filed April 2, 2018.

Capital - Project revenue requirements are $4,504,185 which is $1,791,486 or 28.5% lower than previously projected. As discussed in the testimony of witness Sole filed April 2, 2018, the variance is primarily due to deferrals in capital spending from 2017 to the later part of 2018 for the Turning Basin and Turtle Point Backfill projects as a result of delays in the permitting process.

Project Projections:

(January 1, 2019 to December 31, 2019)

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O&M - Estimated project costs for the projection period are $17,735,378.

Capital - Estimated project revenue requirements for the projection period are $6,534,008.

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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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

Capital - Project revenue requirements are estimated to be $14,919 which is $110 or 0.7% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

Capital - Estimated project revenue requirements for the projection period are $14,491.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: 800MW Unit ESP Project

Project No. 45

Project Description:

On December 21, 2011, the Environmental Protection Agency 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 Electrostatic Precipitators ("ESPs") for the 800 MW oil-fired units (Martin Units 1 and 2, Manatee 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 will use 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, FPL installed ESPs on Manatee Units 1 and 2 and Martin Units 1 and 2.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

The installation of ESPs on units 1 and 2 at Martin was completed and placed in service in 2014.

The systems will continue to run through 2018, until the units are retired, with O&M costs for payroll, materials, and contractors. These costs are associated with inspections, preventative maintenance, and repairs needed to operate and maintain the system.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $752,395, which is $70,786 or 8.6% lower than previously projected.

Capital - Project revenue requirements are estimated to be $24,103,096, which is $123,188 or 0.5% lower than previously projected.

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FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2019 to December 31, 2019)

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

Capital - Estimated project revenue requirements for the projection period are $23,290,040.

FORM: 42-5P

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 EPA's delegation of authority, 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. Any additional costs incurred due to new permit requirements are recovered via this project.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

On November 4, 2016, DEP issued a renewed NPDES permit for the St. Lucie Plant. The renewed permit contained several new requirements. One of these requirements was that the plant initiate, by November 4, 2017, a chlorine optimization study consisting of three phases: Phase I consists of project baseline data collection and planning; Phase II is the actual project implementation, which includes preparation, project initiation and completion, and report writing; and Phase III is post-implementation support. A consultant was retained and Phases I and II must be completed by November 4, 2018. Thus far, the plant is conducting a pilot test for the use of chlorine dioxide to replace sodium hypochlorite (bleach) as a biocide in the plant's cooling water system. It was also determined that less bleach could be used in the plant's intake cooling water system. Smaller pumps were installed to directly inject chlorine into that system resulting in a significant cost savings and reduction in the amount of chemical introduced to the environment. In addition, FPL, with assistance from a consultant who has been retained, will utilize a DEP approved mixing zone modeling plan, should the chlorine dioxide prove to be ineffective, such that the plant would continue to use sodium hypochlorite as a biocide for the plant's once-through cooling water system.

In another 2018 project, the Martin Plant NPDES Permit is being renewed in 2018. DEP has informed FPL that the new permit will contain a discharge limit for a new parameter, total ammonia as nitrogen ("TAN"). 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 or installation of a treatment system. Therefore, Martin Plant has applied to DEP to obtain a Site Specific Alternative Criterion ("SSAC") for the site which is issued under Rule 62-302.800, F.A.C. The process for obtaining the SSAC requires the amendment of Rule 62-302.520(3), F.A.C. The process for amending the rule includes an application, a public workshop, and approval by the Environmental Regulatory Commission ("ERC"), and, ultimately, the DEP Secretary. FPL estimates this process will result in approximately $20,000 of ECRC related expenses. Costs for the studies required to justify the SSAC were expensed under a base account. Should the ERC or DEP not approve the SSAC, FPL will have to explore alternative treatment methods to allow the discharges to meet the new TAN limits at Martin Plant. The following additional activity also occurred in 2018:

- Whole Effluent Toxicity ("WET") Testing – WET testing was conducted at Cape Canaveral, Lauderdale, Ft. Myers, Riviera and St. Lucie plants.

For informational purposes, FPL notes that it submitted a petition on March 5, 2018, and testimony on April 2, 2018, regarding recovery of the cost for replacing the cooling tower packing in Plant Scherer Unit 4 which is partially owned by FPL. The estimated cost for FPL's portion of this project was $9 million. The actual cost of the project, which began in March 2018 after submittal of the petition and was completed in May 2018, was $7.9 million. Because the NPDES permit renewal process is still in an early stage, FPL is seeking to defer ECRC recovery only after issuance of the renewed NPDES permit with a requirement to address copper discharges. Prior to that, FPL will exclude the costs incurred for the repacking activity at Plant Scherer Unit 4 from ECRC recoverable accounts and instead will record those costs in base capital accounts. Any associated expenses will likewise be recorded in base expense accounts.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project expenditures are $487,554 which is $189,356 or 63.5% higher than previously projected. The variance is primarily related to the installation of chlorine injection pump skids at the St. Lucie Plant. These pumps are projected to cost effectively optimize chlorine use in the intake cooling water system, which is a requirement of the facility's Florida Department of Environmental Protection Industrial Wastewater Facility Permit No. FL0002208. Study work on

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FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

chlorine optimization of the remaining St. Lucie Plant water systems is ongoing and additional activities will likely be identified and implemented prior to completion of the study.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $45,127.

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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. In EPA's final rule it published notice that it intended to reconsider the major source rule, as well as the final rule establishing emissions standards for boilers located at area sources. *(See 76 Fed. Reg.15266).* 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 the requirements of the rule.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

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 completed all required one-time energy audits at all of its affected facilities. FPL has also 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.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $17,000, which is $6,000 or 26.1% lower than previously projected.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $32,000.

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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 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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

There are no projected costs.

Project Projections:

(January 1, 2019 to December 31, 2019)

There are no projected costs.

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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 May 2018 EPA published a new plan for implementation of the ELG Rule, which could result in less stringent requirements. EPA is reviewing the rule to determine if the strict requirements for treating or eliminating certain wastestreams are justified. A new draft ELG Rule is expected by December 2018, with a new final rule is expected to be in place by December 2019.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

The operating agent for Plant Scherer conducted studies which looked at a number of possible technology solutions in an attempt to determine the costs for various methods of complying with the ELG Rule under assumptions presented in the proposed rule. Activities necessary to achieve compliance will continue until the compliance dates are officially postponed.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $295,500, which is on target for 2018.

Capital – Estimated revenue requirements for the project are $0

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PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - There are no projected costs.

Capital - Estimated project revenue requirements for the projection period are $31,620.

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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 power 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 Florida Fish and Wildlife Conservation Commission 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, 2018 to December 31, 2018)

In 2018, gopher tortoise burrows were discovered in the Manatee plant's cooling pond that could compromise the embankments' integrity. In order to fill the burrows, the gopher tortoises are expected to be relocated by an authorized gopher tortoise agent by the end of the year. FPL continues through the year to monitor the Martin and Sanford plants' cooling ponds and the Manatee Fuel Oil Storage Terminal embankments as well.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are expected to be $24,649, which is on target for 2018.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projected period are $25,649.

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FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Numeric Nutrient Criteria

Project No. 52

Project Description:

DEP drafted a Numeric Nutrient Criteria ("NNC") rule on June 28, 2013, and EPA accepted the state numeric and narrative standards for freshwaters. On September 26, 2013, EPA accepted DEP's NNC standards for Florida's estuaries. The Environmental Resource Council for the State of Florida adopted the proposed NNC for estuarine and coastal waters on December 1, 2014. DEP submitted the final coastal criteria to EPA in May of 2015. 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, 2018 to December 31, 2018)

There was no activity in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M -There are no projected costs.

Project Projections:

(January 1, 2019 to December 31, 2019)

There are no projected costs for the projection period.

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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, 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.

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 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 continues.

Project Accomplishments:

(January 1, 2018 to December 31, 2018)

Project accomplishments included replacement of the Plant Scherer Unit 4 wet bottom ash handling system, ongoing construction of the common ash management silo area, and CCR water management system.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - There are no projected O&M costs.

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PROJECT DESCRIPTION AND PROGRESS

Capital - Project revenue requirements are estimated to be $3,243,328, which is $291,800 or 9.9% higher than previously projected. The variance is primarily related to higher than projected engineering and construction costs associated with required wastewater treatment and higher than projected quantities of concrete, steel, piping and installation labor hours associated with ash management activities for Plant Scherer. These increases were partially offset by lower than projected costs associated with deferral of the landfill construction.

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $334,680.

Capital - Estimated project revenue requirements for the projection period are $6,033,559.

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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 Florida Fish and Wildlife Conservation Commission ("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, 2018 to December 31, 2018)

Pursuant to Order DR-17-04, FPL is required to conduct four seasons of avian mortality monitoring, including bias trials (carcass persistence and searcher efficiency), and must provide Alachua County an annual report with fatality estimates for birds. FPL will start the standardized mortality monitoring in 2018.

Project Costs:

(January 1, 2018 to December 31, 2018)

O&M - Project costs are estimated to be $69,777.

FORM: 42-5P

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:

(January 1, 2019 to December 31, 2019)

O&M - Estimated project costs for the projection period are $103,493.

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF THE ENERGY DEMAND ALLOCATION % BY RATE CLASS

FORM: 42-6P

JANUARY 2019 THROUGH DECEMBER 2019

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
RATE CLASS	Avg 12 CP Load Factor at Meter (%) [a]	Avg 12 GCP Load Factor at Meter (%) [b]	Projected Sales at Meter (KWH) [c]	Projected Avg 12 CP at Meter (KW) [d]	Projected Avg 12 GCP at Meter (KW) [e]	Demand Loss Expansion Factor [f]	Energy Loss Expansion Factor [g]	Projected Sales at Generation (KWH) [h]	Projected Avg 12 CP at Generation (kW) [i]	Projected Avg 12 GCP Demand at Generation (kW) [j]	Percentage of KWH Sales at Generation (%) [k]	Percentage of 12 CP Demand at Generation (%) [l]	Percentage of 12 GCP Demand at Generation (%) [m]
RS1/RTR1	61.318%	58.772%	57,721,463,189	10,745,888	11,211,559	1.06634038	1.04989745	60,601,616,946	11,458,774	11,955,338	53.39542%	57.65360%	56.94984%
GS1/GST1	62.342%	58.588%	6,158,339,165	1,127,660	1,199,920	1.06634038	1.04989745	6,465,624,579	1,202,469	1,279,523	5.69679%	6.05009%	6.09507%
GSD1/GSDT1/HLFT1	70.809%	67.995%	26,595,865,827	4,287,691	4,465,099	1.06625901	1.04983794	27,921,349,053	4,571,789	4,760,953	24.60119%	23.00247%	22.67903%
OS2	166.935%	14.297%	10,979,898	751	8,767	1.03715166	1.02806009	11,287,995	779	9,092	0.00995%	0.00392%	0.04331%
GSLD1/GSLDT1/CS1/CST1/HLFT2	72.903%	68.240%	10,023,044,160	1,569,457	1,676,700	1.06521841	1.04911329	10,515,308,842	1,671,814	1,786,052	9.26492%	8.41155%	8.50795%
GSLD2/GSLDT2/CS2/CST2/HLFT3	86.130%	81.611%	2,487,110,600	329,636	347,889	1.05518637	1.04156519	2,590,487,824	347,827	367,087	2.28245%	1.75005%	1.74864%
GSLD3/GSLDT3/CS3/CST3	83.216%	71.270%	188,767,478	25,895	30,236	1.02223883	1.01684478	191,947,225	26,471	30,908	0.16912%	0.13319%	0.14723%
SST1T	99.973%	32.858%	107,260,783	12,248	37,265	1.02223883	1.01684478	109,067,567	12,520	38,093	0.09610%	0.06299%	0.18146%
SST1D1/SST1D2/SST1D3	71.831%	38.536%	6,822,549	1,084	2,021	1.03715166	1.02806009	7,013,990	1,125	2,096	0.00618%	0.00566%	0.00998%
CILC D/CILC G	85.780%	83.399%	2,651,228,844	352,823	362,894	1.05481490	1.04141302	2,761,024,242	372,163	382,786	2.43271%	1.87250%	1.82342%
CILC T	92.195%	85.444%	1,426,193,127	176,590	190,543	1.02223883	1.01684478	1,450,217,038	180,517	194,780	1.27777%	0.90825%	0.92784%
MET	76.785%	66.838%	92,084,171	13,690	15,728	1.03715166	1.02806009	94,668,061	14,199	16,312	0.08341%	0.07144%	0.07770%
OL1/SL1/SL1M/PL1	77,451.284%	49.092%	624,537,336	92	145,226	1.06634038	1.04989745	655,700,156	98	154,860	0.57773%	0.00049%	0.73768%
SL2/SL2M/GSCU1	95.338%	94.021%	114,861,786	13,753	13,946	1.06634038	1.04989745	120,593,096	14,666	14,871	0.10625%	0.07379%	0.07084%
Total			108,208,558,913	18,657,257	19,707,791			113,495,906,614	19,875,211	20,992,751	100.00000%	100.00000%	100.00000%

[a] Projected Avg 12 CP load factor based on 2015-2017 load research data and 2019 projections

[b] Projected Avg 12 GCP load factor based on 2015-2017 load research data and 2019 projections

[c] Projected KWH sales for the period January 2019 through December 2019

[d] Calculated: (Col 4)/(8,760 * Col 2)

[e] Calculated: (Col 4)/(8,760 * Col 3)

[f] Based on 2017 demand losses

[g] Based on 2017 energy losses

[h] Col 4 * Col 8

[i] Col 5 * Col 7

[j] Col 6 * Col 7

[k] Col 9 / Total for Col 9

[l] Col 10 / Total for Col 10

[m] Col 11 / Total for Col 11

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
CALCULATION OF ENVIRONMENTAL COST RECOVERY CLAUSE FACTORS

FORM: 42-7P

JANUARY 2019 THROUGH DECEMBER 2019

(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 GCP Demand at Generation (%) [c]	Energy Related Cost ($) [d]	CP Demand Related Cost ($) [e]	GCP Demand Related Cost ($) [f]	Total Environmental Costs ($) [g]	Projected Sales at Meter (kWh) [h]	Environmental Cost Recovery Factor (cents/kWh) [i]
RS1/RTR1	53.39542%	57.65360%	56.94984%	$18,490,024	$71,740,822	$1,408,789	$91,639,635	$57,721,463,189	0.159
GS1/GST1	5.69679%	6.05009%	6.09507%	$1,972,712	$7,528,390	$150,776	$9,651,878	$6,158,339,165	0.157
GSD1/GSDT1/HLFT1	24.60119%	23.00247%	22.67903%	$8,519,020	$28,622,949	$561,020	$37,702,989	$26,595,865,827	0.142
OS2	0.00995%	0.00392%	0.04331%	$3,444	$4,877	$1,071	$9,393	$10,979,898	0.086
GSLD1/GSLDT1/CS1/CST1/HLFT2	9.26492%	8.41155%	8.50795%	$3,208,302	$10,466,854	$210,464	$13,885,620	$10,023,044,160	0.139
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.28245%	1.75005%	1.74864%	$790,378	$2,177,667	$43,257	$3,011,302	$2,487,110,600	0.121
GSLD3/GSLDT3/CS3/CST3	0.16912%	0.13319%	0.14723%	$58,565	$165,729	$3,642	$227,936	$188,767,478	0.121
SST1T	0.09610%	0.06299%	0.18146%	$33,277	$78,385	$4,489	$116,151	$107,260,783	0.108
SST1D1/SST1D2/SST1D3	0.00618%	0.00566%	0.00998%	$2,140	$7,043	$247	$9,430	$6,822,549	0.138
CILC D/CILC G	2.43271%	1.87250%	1.82342%	$842,410	$2,330,029	$45,107	$3,217,546	$2,651,228,844	0.121
CILC T	1.27777%	0.90825%	0.92784%	$442,472	$1,130,177	$22,952	$1,595,601	$1,426,193,127	0.112
MET	0.08341%	0.07144%	0.07770%	$28,884	$88,897	$1,922	$119,703	$92,084,171	0.130
OL1/SL1/SL1M/PL1	0.57773%	0.00049%	0.73768%	$200,059	$614	$18,248	$218,921	$624,537,336	0.035
SL2/SL2M/GSCU1	0.10625%	0.07379%	0.07084%	$36,794	$91,821	$1,752	$130,367	$114,861,786	0.113
TOTAL				$34,628,482	$124,434,252	$2,473,737	$161,536,472	108,208,558,913	0.149

[a] From Form 42-6P, Col 12

[b] From Form 42-6P, Col 13

[c] From Form 42-6P, Col 14

[d] Total Energy $ from Form 42-1P, Line 5

[e] Total CP Demand $ from Form 42-1P, Line 5

[f] Total GCP Demand $ from Form 42-1P, Line 5

[g] Col 5 + Col 6 + Col 7

[h] Projected kWh sales for the period January 2019 through December 2019

[i] Col 8 / Col 9

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

FORM 42-8P

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)

	Separation Factors
DEMAND	
TRANSMISSION	0.892071
SYSTEM AVERAGE PRODUCTION DEMAND (Base and Solar)	0.957589
CONTRACT ADJUSTED DEMAND - INTERMEDIATE	0.942474
CONTRACT ADJUSTED DEMAND - PEAKING	0.953443
ENERGY	
SYSTEM AVERAGE PRODUCTION DEMAND (Base and Solar)	0.959309
CONTRACT ADJUSTED DEMAND - INTERMEDIATE	0.944167
CONTRACT ADJUSTED DEMAND - PEAKING	0.955155
GENERAL PLANT	0.969214
DISTRIBUTION	1.00000

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	339,533	0.0000	0.4095	0.5905	1.0222	1.0372	1.0663	0	144,202	213,798	358,000	1.6068%	1.8012%
CILC-1G	13,290	0.0000	0.0210	0.9790	1.0222	1.0372	1.0663	0	290	13,873	14,163	0.0636%	0.0713%
CILC-1T	176,590	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	180,517	0	0	180,517	0.8102%	0.9083%
GS(T)-1	1,127,660	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	1,202,469	1,202,469	5.3971%	6.0501%
GSCU-1	10,171	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	10,845	10,845	0.0487%	0.0546%
GSD(T)-1	4,287,691	0.0000	0.0028	0.9972	1.0222	1.0372	1.0663	0	12,397	4,559,392	4,571,789	20.5198%	23.0025%
GSLD(T)-1	1,569,457	0.0000	0.0384	0.9616	1.0222	1.0372	1.0663	0	62,569	1,609,245	1,671,814	7.5037%	8.4116%
GSLD(T)-2	329,636	0.0000	0.3821	0.6179	1.0222	1.0372	1.0663	0	130,645	217,182	347,827	1.5612%	1.7501%
GSLD(T)-3	25,895	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	26,471	0	0	26,471	0.1188%	0.1332%
MET	13,690	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	14,199	0	14,199	0.0637%	0.0714%
OL-1	15	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	16	16	0.0001%	0.0001%
OS-2	751	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	779	0	779	0.0035%	0.0039%
RS(T)-1	10,745,888	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	11,458,774	11,458,774	51.4311%	57.6537%
SL-1	76	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	82	82	0.0004%	0.0004%
SL-1M	1	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	1	1	0.0000%	0.0000%
SL-2	3,565	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	3,801	3,801	0.0171%	0.0191%
SL-2M	18	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	19	19	0.0001%	0.0000%
SST-DST	1,084	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	1,125	0	1,125	0.0050%	0.0057%
SST-TST	12,248	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	12,520	0	0	12,520	0.0562%	0.0630%
TOTAL RETAIL	18,657,257							219,508	366,205	19,289,497	19,875,210	89.2071%	100.0000%
FKEC	129,008	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	131,877	0	0	131,877	0.5919%	
FPUC (INT)	13,393	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	13,691	0	0	13,691	0.0614%	
FPUC (PEAK)	14,557	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	14,881	0	0	14,881	0.0668%	
HOMESTEAD	4,402	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	4,500	0	0	4,500	0.0202%	
LCEC	712,376	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	728,219	0	0	728,219	3.2685%	
MOORE HAVEN	571	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	583	0	0	583	0.0026%	
NEW SMRYNA BCH	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0.0000%	
QUINCY	3,098	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	3,167	0	0	3,167	0.0142%	
SEMINOLE (INT)	195,649	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	200,000	0	0	200,000	0.8977%	
WAUCHULA	1,875	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	1,917	0	0	1,917	0.0086%	
WINTER PARK	9,782	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	10,000	0	0	10,000	0.0449%	
TRANS-SERV	1,267,626	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	1,295,816	0	0	1,295,816	5.8161%	
TOTAL WHOLESALE	2,352,336							2,404,650	0	0	2,404,650	10.7929%	
TOTAL FPL	21,009,593							2,624,158	366,205	19,289,497	22,279,860	100.0000%	
JURIS SEPARATION FACTOR												0.892071	

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	339,533	0	339,533	0.0000	0.4095	0.5905	1.0222	1.0372	1.0663	0	144,202	213,798	358,000	1.7248%	1.8012%
CILC-1G	13,290	0	13,290	0.0000	0.0210	0.9790	1.0222	1.0372	1.0663	0	290	13,873	14,163	0.0682%	0.0713%
CILC-1T	176,590	0	176,590	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	180,517	0	0	180,517	0.8697%	0.9083%
GS(T)-1	1,127,660	0	1,127,660	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	1,202,469	1,202,469	5.7935%	6.0501%
GSCU-1	10,171	0	10,171	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	10,845	10,845	0.0523%	0.0546%
GSD(T)-1	4,287,691	0	4,287,691	0.0000	0.0028	0.9972	1.0222	1.0372	1.0663	0	12,397	4,559,392	4,571,789	22.0269%	23.0025%
GSLD(T)-1	1,569,457	0	1,569,457	0.0000	0.0384	0.9616	1.0222	1.0372	1.0663	0	62,569	1,609,245	1,671,814	8.0548%	8.4116%
GSLD(T)-2	329,636	0	329,636	0.0000	0.3821	0.6179	1.0222	1.0372	1.0663	0	130,645	217,182	347,827	1.6758%	1.7501%
GSLD(T)-3	25,895	0	25,895	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	26,471	0	0	26,471	0.1275%	0.1332%
MET	13,690	0	13,690	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	14,199	0	14,199	0.0684%	0.0714%
OL-1	15	0	15	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	16	16	0.0001%	0.0001%
OS-2	751	0	751	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	779	0	779	0.0038%	0.0039%
RS(T)-1	10,745,888	0	10,745,888	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	11,458,774	11,458,774	55.2084%	57.6536%
SL-1	76	0	76	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	82	82	0.0004%	0.0004%
SL-1M	1	0	1	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	1	1	0.0000%	0.0000%
SL-2	3,565	0	3,565	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	3,801	3,801	0.0183%	0.0191%
SL-2M	18	0	18	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	19	19	0.0001%	0.0001%
SST-DST	1,084	0	1,084	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	1,125	0	1,125	0.0054%	0.0057%
SST-TST	12,248	0	12,248	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	12,520	0	0	12,520	0.0603%	0.0630%
TOTAL RETAIL	18,657,257	0	18,657,257							219,508	366,205	19,289,497	19,875,210	95.7589%	100.0000%
FKEC	129,008	0	129,008	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	131,877	0	0	131,877	0.6354%	
FPUC (INT)	13,393	(13,393)	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0.0000%	
FPUC (PEAK)	14,557	(14,557)	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0.0000%	
HOMESTEAD	4,402	0	4,402	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	4,500	0	0	4,500	0.0217%	
LCEC	712,376	0	712,376	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	728,219	0	0	728,219	3.5086%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	583	0	0	583	0.0028%	
NEW SMRYNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0.0000%	
QUINCY	3,098	0	3,098	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	3,167	0	0	3,167	0.0153%	
SEMINOLE (INT)	195,649	(195,649)	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0.0000%	
WAUCHULA	1,875	0	1,875	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	1,917	0	0	1,917	0.0092%	
WINTER PARK	9,782	0	9,782	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	10,000	0	0	10,000	0.0482%	
TOTAL WHOLESALE	1,084,711	(223,599)	861,112							880,262	0	0	880,262	4.2411%	
TOTAL FPL	19,741,968	(223,599)	19,518,369							1,099,771	366,205	19,289,497	20,755,473	100.0000%	
JURIS SEPARATION FACTOR														0.957589	

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	339,533	0	339,533	0.0000	0.4095	0.5905	1.0222	1.0372	1.0663	0	144,202	213,798	358,000	358,000	1.6976%	1.8012%
CILC-1G	13,290	0	13,290	0.0000	0.0210	0.9790	1.0222	1.0372	1.0663	0	290	13,873	14,163	14,163	0.0672%	0.0713%
CILC-1T	176,590	0	176,590	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	180,517	0	0	180,517	180,517	0.8560%	0.9083%
GS(T)-1	1,127,660	0	1,127,660	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	1,202,469	1,202,469	1,202,469	5.7021%	6.0501%
GSCU-1	10,171	0	10,171	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	10,845	10,845	10,845	0.0514%	0.0546%
GSD(T)-1	4,287,691	0	4,287,691	0.0000	0.0028	0.9972	1.0222	1.0372	1.0663	0	12,397	4,559,392	4,571,789	4,571,789	21.6792%	23.0025%
GSLD(T)-1	1,569,457	0	1,569,457	0.0000	0.0384	0.9616	1.0222	1.0372	1.0663	0	62,569	1,609,245	1,671,814	1,671,814	7.9277%	8.4116%
GSLD(T)-2	329,636	0	329,636	0.0000	0.3821	0.6179	1.0222	1.0372	1.0663	0	130,645	217,182	347,827	347,827	1.6494%	1.7501%
GSLD(T)-3	25,895	0	25,895	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	26,471	0	0	26,471	26,471	0.1255%	0.1332%
MET	13,690	0	13,690	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	14,199	0	14,199	14,199	0.0673%	0.0714%
OL-1	15	0	15	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	16	16	16	0.0001%	0.0001%
OS-2	751	0	751	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	779	0	779	779	0.0037%	0.0039%
RS(T)-1	10,745,888	0	10,745,888	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	11,458,774	11,458,774	11,458,774	54.3370%	57.6536%
SL-1	76	0	76	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	82	82	82	0.0004%	0.0004%
SL-1M	1	0	1	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	1	1	1	0.0000%	0.0000%
SL-2	3,565	0	3,565	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	3,801	3,801	3,801	0.0180%	0.0191%
SL-2M	18	0	18	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	19	19	19	0.0001%	0.0001%
SST-DST	1,084	0	1,084	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	1,125	0	1,125	1,125	0.0053%	0.0057%
SST-TST	12,248	0	12,248	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	12,520	0	0	12,520	12,520	0.0594%	0.0630%
TOTAL RETAIL	18,657,257	0	18,657,257							219,508	366,205	19,289,497	19,875,210	19,875,210	94.2474%	100.0000%
FKEC	129,008	0	129,008	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	131,877	0	0	131,877	131,877	0.6254%	
FPUC (INT)	13,393	0	13,393	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	13,691	0	0	13,691	**21,325**	0.1011%	
FPUC (PEAK)	14,557	(14,557)	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0	0.0000%	
HOMESTEAD	4,402	0	4,402	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	4,500	0	0	4,500	4,500	0.0213%	
LCEC	712,376	0	712,376	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	728,219	0	0	728,219	728,219	3.4532%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	583	0	0	583	583	0.0028%	
NEW SMRYNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0	0.0000%	
QUINCY	3,098	0	3,098	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	3,167	0	0	3,167	3,167	0.0150%	
SEMINOLE (INT)	195,649	0	195,649	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	200,000	0	0	200,000	**311,535**	1.4773%	
WAUCHULA	1,875	0	1,875	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	1,917	0	0	1,917	1,917	0.0091%	
WINTER PARK	9,782	0	9,782	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	10,000	0	0	10,000	10,000	0.0474%	
TOTAL WHOLESALE	1,084,711	(14,557)	1,070,154							1,093,953	0	0	1,093,953	1,213,123	5.7526%	
TOTAL FPL	19,741,968	(14,557)	19,727,411							1,313,461	366,205	19,289,497	20,969,163	21,088,333	100.0000%	
JURIS SEPARATION FACTOR															**0.942474**	

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (INT) Amount	SEMINOLE (INT) Amount
1) Contract Wholesale Customer 12 CP	1	Load Research	13,691	200,000
2) Intermediate System Capacity Net of Reserve Margin	2			
Intermediate Summer Capacity	3	2018-2027 TYSP	16,246,000	16,246,000
Divide By: System Capacity Including Reserve Margin	4		120.0%	120.0%
Intermediate System Capacity Net of Reserve Margin	5	L3 / L4	13,538,333	13,538,333
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.001011	0.014773
3) Contract Adjusted 12CP @ Generation	7			
Total System 12CP Excluding All Stratified Contracts	8		20,755,473	20,755,473
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.98422	0.98422
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	21,088,333	21,088,333
Contract Adjusted 12CP @ Generation	11	L6 * L11	21,325	311,535

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	339,533	0	339,533	0.0000	0.4095	0.5905	1.0222	1.0372	1.0663	0	144,202	213,798	358,000	358,000	1.7174%	1.8012%
CILC-1G	13,290	0	13,290	0.0000	0.0210	0.9790	1.0222	1.0372	1.0663	0	290	13,873	14,163	14,163	0.0679%	0.0713%
CILC-1T	176,590	0	176,590	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	180,517	0	0	180,517	180,517	0.8660%	0.9083%
GS(T)-1	1,127,660	0	1,127,660	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	1,202,469	1,202,469	1,202,469	5.7684%	6.0501%
GSCU-1	10,171	0	10,171	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	10,845	10,845	10,845	0.0520%	0.0546%
GSD(T)-1	4,287,691	0	4,287,691	0.0000	0.0028	0.9972	1.0222	1.0372	1.0663	0	12,397	4,559,392	4,571,789	4,571,789	21.9315%	23.0025%
GSLD(T)-1	1,569,457	0	1,569,457	0.0000	0.0384	0.9616	1.0222	1.0372	1.0663	0	62,569	1,609,245	1,671,814	1,671,814	8.0199%	8.4116%
GSLD(T)-2	329,636	0	329,636	0.0000	0.3821	0.6179	1.0222	1.0372	1.0663	0	130,645	217,182	347,827	347,827	1.6686%	1.7501%
GSLD(T)-3	25,895	0	25,895	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	26,471	0	0	26,471	26,471	0.1270%	0.1332%
MET	13,690	0	13,690	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	14,199	0	14,199	14,199	0.0681%	0.0714%
OL-1	15	0	15	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	16	16	16	0.0001%	0.0001%
OS-2	751	0	751	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	779	0	779	779	0.0037%	0.0039%
RS(T)-1	10,745,888	0	10,745,888	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	11,458,774	11,458,774	11,458,774	54.9694%	57.6536%
SL-1	76	0	76	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	82	82	82	0.0004%	0.0004%
SL-1M	1	0	1	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	1	1	1	0.0000%	0.0000%
SL-2	3,565	0	3,565	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	3,801	3,801	3,801	0.0182%	0.0191%
SL-2M	18	0	18	0.0000	0.0000	1.0000	1.0222	1.0372	1.0663	0	0	19	19	19	0.0001%	0.0001%
SST-DST	1,084	0	1,084	0.0000	1.0000	0.0000	1.0222	1.0372	1.0663	0	1,125	0	1,125	1,125	0.0054%	0.0057%
SST-TST	12,248	0	12,248	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	12,520	0	0	12,520	12,520	0.0601%	0.0630%
TOTAL RETAIL	18,657,257	0	18,657,257							219,508	366,205	19,289,497	19,875,210	19,875,210	95.3443%	100.0000%
FKEC	129,008	0	129,008	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	131,877	0	0	131,877	131,877	0.6326%	
FPUC (INT)	13,393	(13,393)	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0	0.0000%	
FPUC (PEAK)	14,557	0	14,557	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	14,881	0	0	14,881	**90,261**	0.4330%	
HOMESTEAD	4,402	0	4,402	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	4,500	0	0	4,500	4,500	0.0216%	
LCEC	712,376	0	712,376	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	728,219	0	0	728,219	728,219	3.4934%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	583	0	0	583	583	0.0028%	
NEW SMRYNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0	0.0000%	
QUINCY	3,098	0	3,098	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	3,167	0	0	3,167	3,167	0.0152%	
SEMINOLE (INT)	195,649	(195,649)	0	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	0	0	0	0	0	0.0000%	
WAUCHULA	1,875	0	1,875	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	1,917	0	0	1,917	1,917	0.0092%	
WINTER PARK	9,782	0	9,782	1.0000	0.0000	0.0000	1.0222	1.0372	1.0663	10,000	0	0	10,000	10,000	0.0480%	
TOTAL WHOLESALE	1,084,711	(209,042)	875,669							895,143	0	0	895,143	970,523	4.6557%	
TOTAL FPL	19,741,968	(209,042)	19,532,926							1,114,651	366,205	19,289,497	20,770,353	20,845,733	100.0000%	
JURIS SEPARATION FACTOR															**0.953443**	

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (PEAK) Amount
1) Contract Wholesale Customer 12 CP	1	Load Research	14,881
2) Peaking System Capacity Net of Reserve Margin	2		
Peaking Summer Capacity	3	2018-2027 TYSP	4,124,000
Divide By: System Capacity Including Reserve Margin	4		120.0%
Peaking System Capacity Net of Reserve Margin	5	L3 / L4	3,436,667
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.00433
3) Contract Adjusted 12CP @ Generation	7		
Total System 12CP Excluding All Stratified Contracts	8		20,755,473
Contribution (Excluding Peaking Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99567
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	20,845,733
Contract Adjusted 12CP @ Generation	11	L6 * L11	90,261

RATE CLASS	MWH SALES			VOLTAGE LEVEL % - ENERGY			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,552,903	0	2,552,903	0.0000	0.4027	0.5973	1.0168	1.0281	1.0499	0	1,056,903	1,600,933	2,657,837	2.2465%	2.3418%
CILC-1G	98,326	0	98,326	0.0000	0.0206	0.9794	1.0168	1.0281	1.0499	0	2,078	101,110	103,188	0.0872%	0.0909%
CILC-1T	1,426,193	0	1,426,193	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	1,450,217	0	0	1,450,217	1.2258%	1.2778%
GS(T)-1	6,158,339	0	6,158,339	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	6,465,625	6,465,625	5.4650%	5.6968%
GSCU-1	84,709	0	84,709	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	88,935	88,935	0.0752%	0.0784%
GSD(T)-1	26,595,866	0	26,595,866	0.0000	0.0027	0.9973	1.0168	1.0281	1.0499	0	74,507	27,846,842	27,921,349	23.6001%	24.6012%
GSLD(T)-1	10,023,044	0	10,023,044	0.0000	0.0359	0.9641	1.0168	1.0281	1.0499	0	370,017	10,145,292	10,515,309	8.8879%	9.2649%
GSLD(T)-2	2,487,111	0	2,487,111	0.0000	0.3816	0.6184	1.0168	1.0281	1.0499	0	975,610	1,614,878	2,590,488	2.1896%	2.2825%
GSLD(T)-3	188,767	0	188,767	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	191,947	0	0	191,947	0.1622%	0.1691%
MET	92,084	0	92,084	0.0000	1.0000	0.0000	1.0168	1.0281	1.0499	0	94,668	0	94,668	0.0800%	0.0834%
OL-1	98,270	0	98,270	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	103,173	103,173	0.0872%	0.0909%
OS-2	10,980	0	10,980	0.0000	1.0000	0.0000	1.0168	1.0281	1.0499	0	11,288	0	11,288	0.0095%	0.0099%
RS(T)-1	57,721,463	0	57,721,463	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	60,601,617	60,601,617	51.2227%	53.3954%
SL-1	522,189	0	522,189	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	548,245	548,245	0.4634%	0.4831%
SL-1M	4,078	0	4,078	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	4,282	4,282	0.0036%	0.0038%
SL-2	29,766	0	29,766	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	31,251	31,251	0.0264%	0.0275%
SL-2M	387	0	387	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	406	406	0.0003%	0.0004%
SST-DST	6,823	0	6,823	0.0000	1.0000	0.0000	1.0168	1.0281	1.0499	0	7,014	0	7,014	0.0059%	0.0062%
SST-TST	107,261	0	107,261	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	109,068	0	0	109,068	0.0922%	0.0961%
TOTAL RETAIL	108,208,559	0	108,208,559							1,751,232	2,592,085	109,152,590	113,495,907	95.9309%	100.0000%
FKEC	811,297	0	811,297	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	824,963	0	0	824,963	0.6973%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0.0000%	
HOMESTEAD	216	0	216	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	220	0	0	220	0.0002%	
LCEC	3,922,167	0	3,922,167	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	3,988,235	0	0	3,988,235	3.3710%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	28	0	0	28	0.0000%	
NEW SMRYNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0.0000%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	155	0	0	155	0.0001%	
SEMINOLE (INT)	741,107	(741,107)	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0.0000%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	94	0	0	94	0.0001%	
WINTER PARK	480	0	480	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	488	0	0	488	0.0004%	
TOTAL WHOLESALE	5,630,722	(896,290)	4,734,432							4,814,182	0	0	4,814,182	4.0691%	
TOTAL FPL	113,839,281	(896,290)	112,942,991							6,565,414	2,592,085	109,152,590	118,310,089	100.0000%	
JURIS SEPARATION FACTOR														0.959309	

RATE CLASS	MWH SALES			VOLTAGE LEVEL % - ENERGY			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	2,552,903	0	2,552,903	0.0000	0.4027	0.5973	1.0168	1.0281	1.0499	0	1,056,903	1,600,933	2,657,837	2,657,837	2.2110%	2.3418%
CILC-1G	98,326	0	98,326	0.0000	0.0206	0.9794	1.0168	1.0281	1.0499	0	2,078	101,110	103,188	103,188	0.0858%	0.0909%
CILC-1T	1,426,193	0	1,426,193	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	1,450,217	0	0	1,450,217	1,450,217	1.2064%	1.2778%
GS(T)-1	6,158,339	0	6,158,339	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	6,465,625	6,465,625	6,465,625	5.3787%	5.6968%
GSCU-1	84,709	0	84,709	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	88,935	88,935	88,935	0.0740%	0.0784%
GSD(T)-1	26,595,866	0	26,595,866	0.0000	0.0027	0.9973	1.0168	1.0281	1.0499	0	74,507	27,846,842	27,921,349	27,921,349	23.2276%	24.6012%
GSLD(T)-1	10,023,044	0	10,023,044	0.0000	0.0359	0.9641	1.0168	1.0281	1.0499	0	370,017	10,145,292	10,515,309	10,515,309	8.7476%	9.2649%
GSLD(T)-2	2,487,111	0	2,487,111	0.0000	0.3816	0.6184	1.0168	1.0281	1.0499	0	975,610	1,614,878	2,590,488	2,590,488	2.1550%	2.2825%
GSLD(T)-3	188,767	0	188,767	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	191,947	0	0	191,947	191,947	0.1597%	0.1691%
MET	92,084	0	92,084	0.0000	1.0000	0.0000	1.0168	1.0281	1.0499	0	94,668	0	94,668	94,668	0.0788%	0.0834%
OL-1	98,270	0	98,270	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	103,173	103,173	103,173	0.0858%	0.0909%
OS-2	10,980	0	10,980	0.0000	1.0000	0.0000	1.0168	1.0281	1.0499	0	11,288	0	11,288	11,288	0.0094%	0.0099%
RS(T)-1	57,721,463	0	57,721,463	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	60,601,617	60,601,617	60,601,617	50.4142%	53.3954%
SL-1	522,189	0	522,189	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	548,245	548,245	548,245	0.4561%	0.4831%
SL-1M	4,078	0	4,078	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	4,282	4,282	4,282	0.0036%	0.0038%
SL-2	29,766	0	29,766	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	31,251	31,251	31,251	0.0260%	0.0275%
SL-2M	387	0	387	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	406	406	406	0.0003%	0.0004%
SST-DST	6,823	0	6,823	0.0000	1.0000	0.0000	1.0168	1.0281	1.0499	0	7,014	0	7,014	7,014	0.0058%	0.0062%
SST-TST	107,261	0	107,261	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	109,068	0	0	109,068	109,068	0.0907%	0.0961%
TOTAL RETAIL	108,208,559	0	108,208,559							1,751,232	2,592,085	109,152,590	113,495,907	113,495,907	94.4167%	100.0000%
FKEC	811,297	0	811,297	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	824,963	0	0	824,963	824,963	0.6863%	
FPUC (INT)	101,728	0	101,728	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	103,442	0	0	103,442	**121,559**	0.1011%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0	0.0000%	
HOMESTEAD	216	0	216	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	220	0	0	220	220	0.0002%	
LCEC	3,922,167	0	3,922,167	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	3,988,235	0	0	3,988,235	3,988,235	3.3178%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	28	0	0	28	28	0.0000%	
NEW SMRYNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0	0.0000%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	155	0	0	155	155	0.0001%	
SEMINOLE (INT)	741,107	0	741,107	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	753,591	0	0	753,591	**1,775,809**	1.4773%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	94	0	0	94	94	0.0001%	
WINTER PARK	480	0	480	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	488	0	0	488	488	0.0004%	
TOTAL WHOLESALE	5,630,722	(53,455)	5,577,267							5,671,215	0	0	5,671,215	6,711,550	5.5833%	
TOTAL FPL	113,839,281	(53,455)	113,785,826							7,422,447	2,592,085	109,152,590	119,167,122	120,207,456	100.0000%	
JURIS SEPARATION FACTOR															**0.944167**	

Contract Adjusted MWH Sales @ Generation -	Line No.	Source/Formula	FPUC (INT) Amount	SEMINOLE (INT) Amount
1) Contract Wholesale Customer 12CP	1	Load Forecast	13,691	200,000
2) Intermediate System Capacity Net of Reserve Margin	2			
Intermediate Summer Capacity	3	2017-2026 TYSP	16,246,000	16,246,000
Divide By: System Capacity Including Reserve Margin	4		120.00%	120.00%
Intermediate System Capacity Net of Reserve Margin	5	L3 / L4	13,538,333	13,538,333
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.101%	1.477%
3) Contract Adjusted MWH Sales @ Generation	7			
Total System MWH Sales @ Generation Excluding Intermediate Stratified Contracts	8		118,310,089	118,310,089
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.98422	0.98422
Total System MWH Sales @ Generation Including Intermediate Stratified Contracts	10	L8 / L9	120,207,456	120,207,456
Contract Adjusted MWH Sales @ Generation	11	L6 * L10	121,559	1,775,809

RATE CLASS	MWH SALES			VOLTAGE LEVEL % - ENERGY			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	2,552,903	0	2,552,903	0.0000	0.4027	0.5973	1.0168	1.0281	1.0499	0	1,056,903	1,600,933	2,657,837	2,657,837	2.2368%	2.3418%
CILC-1G	98,326	0	98,326	0.0000	0.0206	0.9794	1.0168	1.0281	1.0499	0	2,078	101,110	103,188	103,188	0.0868%	0.0909%
CILC-1T	1,426,193	0	1,426,193	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	1,450,217	0	0	1,450,217	1,450,217	1.2205%	1.2778%
GS(T)-1	6,158,339	0	6,158,339	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	6,465,625	6,465,625	6,465,625	5.4413%	5.6968%
GSCU-1	84,709	0	84,709	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	88,935	88,935	88,935	0.0748%	0.0784%
GSD(T)-1	26,595,866	0	26,595,866	0.0000	0.0027	0.9973	1.0168	1.0281	1.0499	0	74,507	27,846,842	27,921,349	27,921,349	23.4980%	24.6012%
GSLD(T)-1	10,023,044	0	10,023,044	0.0000	0.0359	0.9641	1.0168	1.0281	1.0499	0	370,017	10,145,292	10,515,309	10,515,309	8.8494%	9.2649%
GSLD(T)-2	2,487,111	0	2,487,111	0.0000	0.3816	0.6184	1.0168	1.0281	1.0499	0	975,610	1,614,878	2,590,488	2,590,488	2.1801%	2.2825%
GSLD(T)-3	188,767	0	188,767	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	191,947	0	0	191,947	191,947	0.1615%	0.1691%
MET	92,084	0	92,084	0.0000	1.0000	0.0000	1.0168	1.0281	1.0499	0	94,668	0	94,668	94,668	0.0797%	0.0834%
OL-1	98,270	0	98,270	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	103,173	103,173	103,173	0.0868%	0.0909%
OS-2	10,980	0	10,980	0.0000	1.0000	0.0000	1.0168	1.0281	1.0499	0	11,288	0	11,288	11,288	0.0095%	0.0099%
RS(T)-1	57,721,463	0	57,721,463	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	60,601,617	60,601,617	60,601,617	51.0009%	53.3954%
SL-1	522,189	0	522,189	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	548,245	548,245	548,245	0.4614%	0.4831%
SL-1M	4,078	0	4,078	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	4,282	4,282	4,282	0.0036%	0.0038%
SL-2	29,766	0	29,766	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	31,251	31,251	31,251	0.0263%	0.0275%
SL-2M	387	0	387	0.0000	0.0000	1.0000	1.0168	1.0281	1.0499	0	0	406	406	406	0.0003%	0.0004%
SST-DST	6,823	0	6,823	0.0000	1.0000	0.0000	1.0168	1.0281	1.0499	0	7,014	0	7,014	7,014	0.0059%	0.0062%
SST-TST	107,261	0	107,261	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	109,068	0	0	109,068	109,068	0.0918%	0.0961%
TOTAL RETAIL	108,208,559	0	108,208,559							1,751,232	2,592,085	109,152,590	113,495,907	113,495,907	95.5155%	100.0000%
FKEC	811,297	0	811,297	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	824,963	0	0	824,963	824,963	0.6943%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	0	53,455	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	54,355	0	0	54,355	**514,504**	0.4330%	
HOMESTEAD	216	0	216	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	220	0	0	220	220	0.0002%	
LCEC	3,922,167	0	3,922,167	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	3,988,235	0	0	3,988,235	3,988,235	3.3564%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	28	0	0	28	28	0.0000%	
NEW SMRYNA BCH	0	0	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0	0.0000%	
NEW SMRYNA BCH (PEAK)	0	0	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0	0.0000%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	155	0	0	155	155	0.0001%	
SEMINOLE (INT)	741,107	(741,107)	0	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	0	0	0	0	0	0.0000%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	94	0	0	94	94	0.0001%	
WINTER PARK	480	0	480	1.0000	0.0000	0.0000	1.0168	1.0281	1.0499	488	0	0	488	488	0.0004%	
TOTAL WHOLESALE	5,630,722	(842,835)	4,787,886							4,868,537	0	0	4,868,537	5,328,686	4.4845%	
TOTAL FPL	113,839,281	(842,835)	112,996,445							6,619,769	2,592,085	109,152,590	118,364,444	118,824,592	100.0000%	
JURIS SEPARATION FACTOR															**0.955155**	

Contract Adjusted MWH Sales @ Generation -	Line No.	Source/Formula	FPUC (PEAK) Amount
1) Contract Wholesale Customer 12 CP	1	Load Forecast	14,881
2) Peaker System Capacity Net of Reserve Margin	2		
Peaker Summer Capacity	3	2017-2026 TYSP	4,124,000
Divide By: System Capacity Including Reserve Margin	4		120.00%
Peaker System Capacity Net of Reserve Margin	5	L3 / L4	3,436,667
Contract Rate Class Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.433%
3) Contract Adjusted MWH Sales @ Generation	7		
Total System MWH Sales @ Generation Excluding Peaker Stratified Contracts	8		118,310,089
Contribution (Excluding Peaker Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99567
Total System MWH Sales @ Generation Including Peaker Stratified Contracts	10	L8 / L9	118,824,592
Contract Adjusted 12CP @ Generation	11	L6 * L10	514,504

SEP - INTERNAL FACTORS BASED ON EXTERNAL FACTORS	ALLOCATOR	COMPANY PER BOOKS	SEPARATION FACTOR	JURISDICTIONAL	INTERNAL SEPARATION FACTOR
I900-LABOR-EXC-A&G					
L_INC100000 - STEAM O&M PAY - OPERAT SUPERV & ENG	FPL102NS, FPL103INT, FPL103PK	1,898,365.92	0.955732	1,814,329.83	
L_INC101210 - STEAM O&M PAY - FUEL - NON RECOVERABLE OIL	FPL202NS, FPL203INT, FPL203PK	426,052.30	0.954077	406,486.72	
L_INC102000 - STEAM O&M PAY - STEAM EXPENSES	FPL102NS, FPL103INT, FPL103PK	1,202,629.84	0.956751	1,150,617.35	
L_INC105000 - STEAM O&M PAY - ELECTRIC EXPENSES	FPL102NS, FPL103INT, FPL103PK	640,861.42	0.955377	612,264.04	
L_INC106000 - STEAM O&M PAY - MISC STEAM POWER EXPENSES	FPL102NS, FPL103INT, FPL103PK	7,883,586.61	0.953140	7,514,161.27	
L_INC110000 - STEAM O&M PAY - MAINT SUPERV & ENG	FPL202NS, FPL203INT, FPL203PK	837,817.01	0.958399	802,962.77	
L_INC111000 - STEAM O&M PAY - MAINT OF STRUCTURES	FPL102NS, FPL103INT, FPL103PK	1,558,786.82	0.954277	1,487,513.91	
L_INC112000 - STEAM O&M PAY - MAINT OF BOILER PLANT	FPL202NS, FPL203INT, FPL203PK	2,716,254.92	0.957680	2,601,302.13	
L_INC113000 - STEAM O&M PAY - MAINT OF ELECTRIC PLANT	FPL202NS, FPL203INT, FPL203PK	1,185,016.20	0.957196	1,134,292.55	
L_INC114000 - STEAM O&M PAY - MAINT OF MISC STEAM PLT	FPL202NS, FPL203INT, FPL203PK	986,176.18	0.956459	943,237.08	
L_INC117000 - NUCLEAR O&M PAY - OPER SUPERV & ENG	FPL102NS	50,819,986.29	0.957589	48,664,655.11	
L_INC119000 - NUCLEAR O&M PAY - COOLANTS AND WATER	FPL102NS	6,615,221.33	0.957589	6,334,662.56	
L_INC120000 - NUCLEAR O&M PAY - STEAM EXPENSES	FPL102NS	50,306,099.61	0.957589	48,172,562.93	
L_INC123000 - NUCLEAR O&M PAY - ELECTRIC EXP	FPL102NS	1,546.56	0.957589	1,480.97	
L_INC124000 - NUCLEAR O&M PAY - MISC NUCLEAR POWER EXP	FPL102NS	25,553,445.56	0.957589	24,469,695.99	
L_INC128000 - NUCLEAR O&M PAY - MAINT SUPERVISION & ENGINEERING	FPL202NS	52,716,365.81	0.959309	50,571,272.39	
L_INC129000 - NUCLEAR O&M PAY - MAINT OF STRUCTURES	FPL102NS	96,314.79	0.957589	92,229.97	
L_INC130000 - NUCLEAR O&M PAY - MAINT OF REACTOR PLANT	FPL201	48,208.90	0.951975	45,893.69	
L_INC131000 - NUCLEAR O&M PAY - MAINT OF ELECTRIC PLANT	FPL201	485,427.69	0.951975	462,115.20	
L_INC132000 - NUCLEAR O&M PAY - MAINT OF MISC NUCLEAR PLANT	FPL201	27,050.63	0.951975	25,751.53	
L_INC146000 - OTH PWR O&M PAY - OPERAT SUPERV & ENG	FPL102NS, FPL103INT, FPL103PK	8,893,152.54	0.944383	8,398,537.91	
L_INC147200 - OTH PWR O&M PAY - FUEL N- RECOV EMISSIONS FEE	FPL203INT	2,904,192.82	0.944167	2,742,042.85	
L_INC148000 - OTH PWR O&M PAY- GENERATION EXPENSES	FPL103INT, FPL103PK	9,064,707.96	0.943473	8,552,309.84	
L_INC149000 - OTH PWR O&M PAY - MISC OTHER POWER GENERATION EXPENSE	FPL103INT, FPL103PK	17,904,186.99	0.944353	16,907,867.85	
L_INC151000 - OTH PWR O&M PAY - MAINT SUPERV & ENG	FPL203INT, FPL203PK	5,201,669.97	0.945871	4,920,107.32	
L_INC152000 - OTH PWR O&M PAY - MAINT OF STRUCTURES	FPL103INT, FPL103PK	4,323,485.15	0.943659	4,079,895.18	
L_INC153000 - OTH PWR O&M PAY - MAINT GENERATING & ELECTRIC PLANT	FPL203INT, FPL203PK	21,242,701.14	0.945593	20,086,939.79	
L_INC154000 - OTH PWR O&M PAY - MAINT MISC OTHER PWR GENERAT	FPL203INT, FPL203PK	4,280,194.02	0.944350	4,042,002.94	
L_INC156000 - OTH PWR O&M PAY - SYSTEM CONTROL & LOAD DISPATCH	FPL103INT	648,714.10	0.942474	611,396.32	
L_INC157000 - OTH PWR O&M PAY - OTHER EXPENSES LOC 955	FPL103INT	1,970,050.95	0.942474	1,856,722.23	
L_INC260010 - TRANS O&M PAY - OPERATION SUPERV & ENGINEERING	FPL101	4,123,610.64	0.892071	3,678,552.24	
L_INC261000 - TRANS O&M PAY - LOAD DISPATCHING	FPL101	2,594,046.65	0.892071	2,314,073.02	
L_INC262000 - TRANS O&M PAY - STATION EXPENSES	FPL101	260,139.60	0.892071	232,062.92	
L_INC263000 - TRANS O&M PAY - OVERHEAD LINE EXPENSES	FPL101	64,663.29	0.892071	57,684.23	
L_INC266000 - TRANS O&M PAY - MISC TRANSMISSION EXPENSES	FPL101	3,740,322.49	0.892071	3,336,632.11	
L_INC267000 - TRANS O&M - RENTS	FPL101				
L_INC268010 - TRANS O&M PAY - MAINT SUPERV & ENG	FPL101	1,180,313.03	0.892071	1,052,922.67	
L_INC269000 - TRANS O&M PAY - MAINT OF STRUCTURES	FPL101	2,353,903.14	0.892071	2,099,848.03	
L_INC270000 - TRANS O&M PAY - MAINT OF STATION EQ	FPL101	1,921,853.74	0.892071	1,714,429.41	
L_INC271000 - TRANS O&M PAY - MAINT OF OVERHEAD LINES	FPL101	1,972,214.71	0.892071	1,759,354.96	
L_INC272000 - TRANS O&M PAY - MAINT UNDERGROUND LINES	FPL101	23,814.57	0.892071	21,244.28	
L_INC273000 - TRANS O&M PAY - MAINT OF MISC TRANS PLANT	FPL101				
L_INC380000 - DIST O&M PAY - OPERATION SUPERVISION AND ENGINEERING	FPL104	10,851,450.36	1.000000	10,851,450.36	
L_INC381000 - DIST O&M PAY - LOAD DISPATCHING	FPL104				
L_INC382000 - DIST O&M PAY - SUBSTATION EXPENSES	FPL104	572,271.36	1.000000	572,271.36	
L_INC383000 - DIST O&M PAY - OVERHEAD LINE EXPENSES	I365T	4,282,615.23	1.000000	4,282,615.23	
L_INC384000 - DIST O&M PAY - UNDERGROUND LINE EXP	I367T	1,466,642.64	1.000000	1,466,642.64	
L_INC385000 - DIST O&M PAY - STREET LIGHTING AND SIGNAL SYSTEM EXPENSE	FPL508	141,913.75	1.000000	141,913.75	
L_INC386000 - DIST O&M PAY - METER EXPENSES	FPL325	8,850,462.35	0.998659	8,838,589.68	
L_INC387000 - DIST O&M PAY - CUSTOMER INSTALLATIONS EXP	FPL309	1,066,725.24	1.000000	1,066,725.24	
L_INC388000 - DIST O&M PAY - MISC DISTRIBUTION EXPENSES	FPL104	28,682,488.78	1.000000	28,682,488.78	
L_INC389000 - DIST O&M - RENTS	FPL104				
L_INC390000 - DIST O&M PAY - MAINT SUPERV & ENG	FPL104	14,522,381.55	1.000000	14,522,381.55	
L_INC391000 - DIST O&M PAY - MAINT OF STRUCTURES	FPL104	44,545.13	1.000000	44,545.13	
L_INC392000 - DIST O&M PAY - MAINT OF STATION EQ	FPL104	3,048,449.85	1.000000	3,048,449.85	
L_INC393000 - DIST O&M PAY - MAINT OF OVERHEAD LINES	I365T	28,826,501.09	1.000000	28,826,501.09	
L_INC394000 - DIST O&M PAY - MAINT UNDERGROUND LINES	I367T	12,347,639.66	1.000000	12,347,639.66	
L_INC395000 - DIST O&M PAY - MAINT OF LINE TRANSFORMERS	FPL104	35,192.06	1.000000	35,192.06	
L_INC396000 - DIST O&M PAY - MAINT OF STREET LIGHTING & SIGNAL SYSTEMS	FPL508	4,323,505.78	1.000000	4,323,505.78	

SEP - INTERNAL FACTORS BASED ON EXTERNAL FACTORS	ALLOCATOR	COMPANY PER BOOKS	SEPARATION FACTOR	JURISDICTIONAL	INTERNAL SEPARATION FACTOR
L_INC397000 - DIST O&M PAY - MAINT OF METERS	FPL325	2,629,763.60	0.998659	2,626,235.84	
L_INC398000 - DIST O&M PAY - MAINT OF MISC DISTRI PLT	FPL104	586,415.63	1.000000	586,415.63	
L_INC401000 - CUST ACCT O&M PAY - SUPERVISION	I540	5,254,309.22	1.000000	5,254,309.22	
L_INC402000 - CUST ACCT O&M PAY - METER READING EXP	FPL330	4,387,941.67	1.000000	4,387,941.67	
L_INC403000 - CUST ACCT O&M PAY - CUST REC & COLLECT	FPL356	42,143,241.70	1.000000	42,143,241.70	
L_INC404000 - CUST ACCT EXP - UNCOLLECTIBLE ACCOUNTS	FPL205	1,366.11	1.000000	1,366.11	
L_INC405000 - CUST ACCT O&M PAY - MISC CUSTOMER ACCOUNTS EXPENSES	FPL355				
L_INC407000 - CUST SERV & INFO PAY - SUPERVISION	FPL356	1,672,574.02	1.000000	1,672,574.02	
L_INC408000 - CUST SERV & INFO PAY - CUST ASSIST EXP	FPL356	1,955,505.36	1.000000	1,955,505.36	
L_INC409000 - CUST SERV & INFO PAY - INFO & INST ADV - GENERAL	FPL355				
L_INC410000 - CUST SERV & INFO PAY - MISC CUST SERV & INF	FPL356	5,005,378.67	1.000000	5,005,378.67	
L_INC411000 - SUPERVISION-SALES EXPENSES	FPL356				
L_INC516000 - MISC AND SELLING EXPENSES	FPL356	1,141,765.47	1.000000	1,141,765.47	
Total I900-LABOR-EXC-A&G		484,514,198.16		469,597,759.96	**0.969214**

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Commission Forms 42-1A Through 42-9A

January 2017 - December 2017
Final True-Up
Docket No. 20180007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 15
PARTY: DUKE ENERGY FLORIDA, INC. (DEF)(DIRECT)
DESCRIPTION: Christopher Menendez

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2017 - December 2017
(in Dollars)

Form 42-1A

Docket No. 20180007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)

Line		Period Amount
1	Over/(Under) Recovery for the Period January 2017 - December 2017 (Form 42-2A, Line 5 + 6 + 10)	$ 6,565,806
2	Actual/Estimated True-Up Amount Approved for the Period January 2017 - December 2017 (Order No. PSC-2018-0014-FOF-EI)	1,751,015
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2019 to December 2019 (Lines 1 - 2)	$ 4,814,791

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2017 - December 2017

End-of-Period True-Up Amount
(in Dollars)

Form 42-2A

Docket No. 20180007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)

Line	Description		Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$3,787,753	$3,955,395	$ 3,785,440.63	$ 4,188,871.45	$4,662,865	$5,197,777	$5,598,804	$5,632,809	$5,619,685	$4,918,168	$4,592,864	$4,086,678	56,027,109
2	True-Up Provision	8,557,918	$713,160	$713,160	$713,160	$713,160	$713,160	$713,160	$713,160	$713,160	$713,160	$713,160	$713,160	$713,160	8,557,918
	(Order No. PSC-2016-0535-FOF-EI)														
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		$4,500,913	4,668,555	4,498,600	4,902,031	5,376,025	5,910,936	6,311,964	6,345,968	6,332,845	5,631,328	5,306,023	4,799,837	64,585,027
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		$2,727,750	$2,658,162	$3,255,691	$2,744,695	$3,781,772	$2,903,683	$2,739,658	$3,137,720	$2,743,658	$3,166,145	$1,836,037	$2,450,866	$34,145,837
	b. Capital Investment Projects (Form 42-7A, Line 9)		2,008,193	1,998,642	1,986,655	1,937,659	1,937,636	1,973,768	1,958,754	1,955,499	1,994,714	2,015,205	2,073,494	2,101,824	23,942,044
	c. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Total Jurisdictional ECRC Costs		$4,735,943	$4,656,804	$5,242,346	$4,682,354	$5,719,408	$4,877,451	$4,698,412	$5,093,219	$4,738,372	$5,181,350	$3,909,531	$4,552,690	$58,087,881
5	Over/(Under) Recovery (Line 3 - Line 4d)		($235,030)	$11,751	($743,746)	$219,677	($343,383)	$1,033,485	$1,613,552	$1,252,749	$1,594,473	$449,978	$1,396,492	$247,148	$6,497,146
6	Interest Provision (Form 42-3A, Line 10)		4,488	4,947	4,921	4,864	4,287	4,549	5,489	6,090	5,556	6,024	7,939	9,506	68,660
7	Beginning Balance True-Up & Interest Provision		8,557,918	7,614,216	6,917,755	5,465,770	4,977,151	3,924,895	4,249,769	5,155,650	5,701,329	6,588,199	6,331,041	7,022,312	8,557,918
	a. Deferred True-Up - January 2016 - December 2016														
	(2016 TU filing dated 4/3/17, approved in Order PSC-2018-0014-FOF-EI)		1,266,492	1,266,492	1,266,492	1,266,492	1,266,492	1,266,492	1,266,492	1,266,492	1,266,492	1,266,492	1,266,492	1,266,492	1,266,492
8	True-Up Collected/(Refunded) (see Line 2)		(713,160)	(713,160)	(713,160)	(713,160)	(713,160)	(713,160)	(713,160)	(713,160)	(713,160)	(713,160)	(713,160)	(713,160)	(8,557,918)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		$8,880,708	$8,184,247	$6,732,262	$6,243,643	$5,191,387	$5,516,261	$6,422,142	$6,967,821	$7,854,691	$7,597,533	$8,288,804	$7,832,298	$7,832,298
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)		$8,880,708	$8,184,247	$6,732,262	$6,243,643	$5,191,387	$5,516,261	6,422,142	$6,967,821	$7,854,691	$7,597,533	$8,288,804	$7,832,298	$7,832,298

Notes:
(A) N/A

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2017 - December 2017

Interest Provision
(in Dollars)

Line	Description	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$9,824,410	$8,880,708	$8,184,247	$6,732,262	$6,243,643	$5,191,387	$5,516,261	$6,422,142	$6,967,821	$7,854,691	$7,597,533	$8,288,804	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	8,876,220	8,179,300	6,727,341	6,238,779	5,187,100	5,511,712	6,416,653	6,961,731	7,849,135	7,591,509	8,280,865	7,822,792	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	18,700,630	17,060,008	14,911,588	12,971,041	11,430,743	10,703,099	11,932,914	13,383,874	14,816,956	15,446,200	15,878,398	16,111,596	
4	Average True-Up Amount (Line 3 x 1/2)	9,350,315	8,530,004	7,455,794	6,485,521	5,715,372	5,351,550	5,966,457	6,691,937	7,408,478	7,723,100	7,939,199	8,055,798	
5	Interest Rate (Last Business Day of Prior Month)	0.40%	0.74%	0.64%	0.94%	0.86%	0.95%	1.08%	1.12%	1.06%	0.73%	1.14%	1.25%	
6	Interest Rate (Last Business Day of Current Month)	0.74%	0.64%	0.94%	0.86%	0.95%	1.08%	1.12%	1.06%	0.73%	1.14%	1.25%	1.58%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	1.14%	1.38%	1.58%	1.80%	1.81%	2.03%	2.20%	2.18%	1.79%	1.87%	2.39%	2.83%	
8	Average Interest Rate (Line 7 x 1/2)	0.570%	0.690%	0.790%	0.900%	0.905%	1.015%	1.100%	1.090%	0.895%	0.935%	1.195%	1.415%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.048%	0.058%	0.066%	0.075%	0.075%	0.085%	0.092%	0.091%	0.075%	0.078%	0.100%	0.118%	
10	Interest Provision for the Month (Line 4 x Line 9)	$4,488	$4,947	$4,921	$4,864	$4,287	$4,549	$5,489	$6,090	$5,556	$6,024	$7,939	$9,506	$68,660

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2017 - December 2017

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	$367,391	$579,423	($212,032)	-37%
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	517,025	625,998	(108,973)	-17%
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	5,111	36,159	(31,048)	-86%
3	Pipeline Integrity Management - Bartow /Anclote Pipeline - Intm	(10,208)	0	(10,208)	0%
4	Above Ground Tank Secondary Containment	0	0	0	0%
5	SO2/NOx Emissions Allowances - Energy	14,242	20,505	(6,263)	-31%
5	NOx Emissions Allowances Regulatory Asset	3,673,973	3,673,974	(1)	0%
6	Phase II Cooling Water Intake 316(b) - Base	300,130	190,686	109,445	57%
6a	Phase II Cooling Water Intake 316(b) - Intm	28,803	36,054	(7,251)	-20%
7.2	CAIR/CAMR - Peaking - Demand	0	0	(0)	0%
7.4	CAIR/CAMR Crystal River - Base	13,318,899	14,378,699	(1,059,800)	-7%
7.4	CAIR/CAMR Crystal River - Energy	15,392,099	19,174,599	(3,782,500)	-20%
7.4	CAIR/CAMR Crystal River - A&G	131,185	143,898	(12,712)	-9%
7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	0	0	0	0%
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0%
8	Arsenic Groundwater Standard - Base	102,758	120,262	(17,504)	-15%
9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0%
11	Modular Cooling Towers - Base	0	0	0	0%
12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0%
13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0%
14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0%
15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0%
15.1	Effluent Limitation Guidelines ICR Program CRN - Energy	0	0	0	0%
16	National Pollutant Discharge Elimination System (NPDES) - Energy	26,438	70,198	(43,760)	-62%
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	134,409	598,439	(464,030)	-78%
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	1,924,271	1,790,786	133,485	7%
18	Coal Combustion Residual (CCR) Rule - Energy	383,150	472,101	(88,951)	-19%
2	Total O&M Activities - Recoverable Costs	$36,309,677	$41,911,781	($5,602,103)	-13%
3	Recoverable Costs Allocated to Energy	21,548,581	25,800,601	(4,252,020)	-16%
4	Recoverable Costs Allocated to Demand	14,761,096	16,111,179	(1,350,083)	-8%

Notes:
Column (1) End of Period Totals on Form 42-5A
Column (2) 2017 Estimated/Actual Filing (8/4/2017)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2017 - December 2017

O&M Activities
(in Dollars)

Form 42-5A

Docket No. 20180007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)

Line	Description	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Description of O&M Activities													
1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$87,099	($20,298)	$23,596	$14,750	$384,276	($257,407)	$33,417	$61,473	$11,735	$8,764	$2,822	$17,164	$367,391
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	85,273	12,198	40,914	152,855	44,759	43,321	34,720	18,440	(2,703)	9,643	966	76,640	517,025
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	1,693	1,514	0	16,111	11,151	(25,358)	0	0	0	0	0	0	5,111
3	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	0	0	0	0	0	0	0	0	(10,208)	0	0	0	(10,208)
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	6,740	2,619	2,198	2,622	2,563	(25,148)	2,580	2,376	2,919	2,324	9,873	2,576	14,242
5	NOx Emissions Allowance Regulatory Asset	302,430	302,430	302,430	302,430	302,430	302,430	302,430	311,393	311,393	311,393	311,393	311,393	3,673,973
6	Phase II Cooling Water Intake 316(b) - Base	(48,845)	30,910	0	58,168	0	26,647	19,955	0	63,209	13,897	8,501	127,690	300,130
6a	Phase II Cooling Water Intake 316(b) - Intm	24,827	(6,903)	19,730	(31,837)	24,557	(5,780)	19,089	24,077	(44,413)	(4,035)	21,762	(12,270)	28,803
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	894,732	927,983	1,253,291	672,296	1,362,423	941,744	980,901	1,411,476	969,671	1,429,356	1,313,160	1,161,865	13,318,899
7.4	CAIR/CAMR Crystal River - Energy	1,295,612	1,284,869	1,536,151	1,533,104	1,801,128	1,792,358	1,371,095	1,296,107	1,399,960	1,337,643	79,129	664,942	15,392,099
7.4	CAIR/CAMR Crystal River - A&G	11,040	12,563	15,357	11,320	9,677	10,017	14,902	14,960	8,624	11,741	6,276	4,708	131,185
7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Arsenic Groundwater Standard - Base	5,442	(3,678)	2,371	235	(2,513)	32,526	4,791	8,350	6,554	23,273	600	24,807	102,758
9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
15.1	Effluent Limitation Guidelines ICR Program CRN - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
16	National Pollutant Discharge Elimination System (NPDES) - Energy	2,343	0	7,018	0	2,485	0	0	7,496	0	4,612	2,485	0	26,438
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	(303)	0	6,639	11,783	33,900	4,647	413	19,571	50,399	40,347	(19,208)	(13,780)	134,409
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	92,898	162,556	192,503	155,108	157,189	152,932	123,433	184,150	112,192	169,782	202,077	219,450	1,924,271
18	Coal Combustion Residual (CCR) Rule - Energy	116,353	73,608	37,766	23,601	20,797	24,759	18,073	12,203	20,145	10,211	15,895	9,740	383,150
2	Total of O&M Activities	$2,877,333	$2,780,370	$3,439,964	$2,922,547	$4,154,822	$3,017,688	$2,925,798	$3,372,072	$2,899,476	$3,368,952	$1,955,731	$2,594,925	$36,309,677
3	Recoverable Costs Allocated to Energy	1,513,643	1,523,652	1,782,274	1,726,219	2,018,063	1,949,548	1,515,594	1,521,903	1,585,614	1,564,919	290,251	882,929	17,874,609
	Recoverable Costs Allocated to Energy - Nox Regulatory Asset	$302,430	$302,430	$302,430	$302,430	$302,430	$302,430	$302,430	$311,393	$311,393	$311,393	$311,393	$311,393	$3,673,973
4	Recoverable Costs Allocated to Demand - Transm	87,099	(20,298)	23,596	14,750	384,276	(257,407)	33,417	61,473	11,735	8,764	2,822	17,164	367,391
	Recoverable Costs Allocated to Demand - Distrib	86,966	13,711	40,914	168,966	55,910	17,964	34,720	18,440	(2,703)	9,643	966	76,640	522,136
	Recoverable Costs Allocated to Demand - Prod-Base	851,329	955,215	1,255,662	730,699	1,359,910	1,000,917	1,005,646	1,419,826	1,039,434	1,466,526	1,322,261	1,314,362	13,721,788
	Recoverable Costs Allocated to Demand - Prod-Intm	24,827	(6,903)	19,730	(31,837)	24,557	(5,780)	19,089	24,077	(54,621)	(4,035)	21,762	(12,270)	18,595
	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	11,040	12,563	15,357	11,320	9,677	10,017	14,902	14,960	8,624	11,741	6,276	4,708	131,185
5	Retail Energy Jurisdictional Factor	0.96770	0.96390	0.95790	0.92910	0.92670	0.94150	0.93930	0.93370	0.94560	0.94270	0.95880	0.95280	
	Retail Energy Jurisdictional Factor - Nox Regulatory Asset	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	
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)	1,464,753	1,468,648	1,707,240	1,603,830	1,870,139	1,835,499	1,423,598	1,421,001	1,499,357	1,475,249	278,293	841,254	16,888,861
	Jurisdictional Energy Recoverable Costs - Nox Regulatory Asset	296,169	296,169	296,169	296,169	296,169	296,169	296,169	304,947	304,947	304,947	304,947	304,947	3,597,918
8	Jurisdictional Demand Recoverable Costs - Transm (B)	61,146	(14,250)	16,565	10,355	269,773	(180,707)	23,460	43,156	8,239	6,153	1,981	12,049	257,920
	Jurisdictional Demand Recoverable Costs - Distrib (B)	86,584	13,651	40,734	168,224	55,665	17,885	34,567	18,359	(2,691)	9,601	962	76,303	519,844
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	790,757	887,251	1,166,322	678,710	1,263,152	929,702	934,094	1,318,806	965,478	1,362,183	1,228,182	1,220,845	12,745,482
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	18,050	(5,019)	14,345	(23,146)	17,853	(4,203)	13,878	17,505	(39,711)	(2,933)	15,821	(8,921)	13,519
	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)	10,291	11,712	14,316	10,553	9,021	9,338	13,892	13,946	8,039	10,945	5,851	4,389	122,293
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$2,727,750	$2,658,162	$3,255,691	$2,744,695	$3,781,772	$2,903,683	$2,739,658	$3,137,720	$2,743,658	$3,166,145	$1,836,037	$2,450,866	$34,145,837

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 2017 - December 2017

Variance Report of Capital Investment Activities
(In Dollars)

Line			(1) YTD Actual	(2) Actual/ Estimated	(3) Variance Amount	(4) Variance Percent
1	Description of Capital Investment Activities					
	3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline	$721,736	$721,733	$3	0%
	4.x	Above Ground Tank Secondary Containment	1,997,669	1,997,655	14	0%
	5	SO2/NOx Emissions Allowances	504,690	503,547	1,143	0%
	6	Phase II Cooling Water Intake 316(b)	3,235	0	3,235	0%
	7.x	CAIR/CAMR	1,745,568	1,810,165	(64,597)	-4%
	8	Best Available Retrofit Technology (BART)	0	0	0	0%
	9	Sea Turtle - Coastal Street Lighting	1,250	1,250	0	0%
	10.x	Underground Storage Tanks	25,599	25,599	0	0%
	11	Modular Cooling Towers	0	0	0	0%
	11.1	Crystal River Thermal Discharge Compliance Project	0	0	0	0%
	15.1	Effluent Limitation Guidelines CRN (ELG)	18,823	19,537	(714)	-4%
	16	National Pollutant Discharge Elimination System (NPDES)	1,700,609	1,700,614	(5)	0%
	17x	Mercury & Air Toxics Standards (MATS)	19,110,864	19,110,868	(4)	0%
	18	Coal Combustion Residual (CCR) Rule	38,566	39,441	(875)	-2%
2	Total Capital Investment Activities - Recoverable Costs		$25,868,608	$25,930,408	($61,800)	0%
3	Recoverable Costs Allocated to Energy		19,735,928	19,742,411	($6,483)	0%
4	Recoverable Costs Allocated to Demand		$6,132,680	$6,187,997	($55,317)	-1%

Notes:

Column (1) End of Period Totals on Form 42-7A
Column (2) 2017 Actual/Estimated Filing (8/4/2017)
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Final True-Up
January 2017 - December 2017

Capital Investment Projects-Recoverable Costs
(in Dollars)

Form 42-7A

Docket No. 20180007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-1)

Line	Description	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate	$62,010	$61,610	$61,208	$60,807	$60,406	$60,004	60,289	$59,885	$59,483	$59,080	$58,677	$58,275	$721,736
4.1	Above Ground Tank Secondary Containment - Peaking	144,482	143,869	143,263	142,663	142,061	141,458	140,063	139,468	138,873	138,280	137,687	137,090	1,689,257
4.2	Above Ground Tank Secondary Containment - Base	23,451	23,427	23,402	23,376	23,352	23,327	23,036	23,011	22,986	22,962	22,937	22,913	278,180
4.3	Above Ground Tank Secondary Containment - Intermediate	2,555	2,551	2,546	2,542	2,537	2,534	2,505	2,501	2,497	2,492	2,488	2,484	30,232
5	SO2/NOX Emissions Allowances - Energy	56,201	53,694	51,207	48,718	46,229	43,626	40,475	37,983	35,454	32,925	30,368	27,810	504,690
6	Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	109	282	2,844	3,235
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	20,410	20,355	20,302	20,248	20,193	20,139	19,923	19,870	19,816	19,763	19,709	19,655	240,381
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	46,582	48,404	52,698	58,926	69,867	88,845	102,713	115,468	143,213	177,185	218,226	262,686	1,384,813
7.4	CAIR/CAMR Crystal River AFUDC - Energy	11,619	12,108	11,849	10,785	10,058	9,854	9,202	9,174	9,220	8,683	8,723	9,099	120,374
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	106	106	105	105	105	105	104	104	103	103	102	102	1,250
10.1	Underground Storage Tanks - Base	1,478	1,475	1,473	1,470	1,468	1,465	1,448	1,447	1,444	1,442	1,439	1,437	17,486
10.2	Underground Storage Tanks - Intermediate	688	686	685	683	681	680	673	671	669	668	665	664	8,113
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	128	897	1,272	1,547	1,899	2,063	1,887	1,826	1,826	1,826	1,826	1,826	18,823
16	National Pollutant Discharge Elimination System (NPDES) - Intermediate	143,953	143,668	143,376	143,084	142,794	142,502	140,924	140,636	140,349	140,062	139,774	139,487	1,700,609
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	35,715	35,662	35,607	35,554	35,501	35,447	35,006	34,952	34,899	34,846	34,793	34,740	422,726
17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	1,343,285	1,341,306	1,339,327	1,337,348	1,335,369	1,333,391	1,317,865	1,315,912	1,313,960	1,312,008	1,310,056	1,308,103	15,907,924
17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	235,929	235,363	234,798	234,233	233,667	233,102	230,247	229,689	229,132	228,574	228,016	227,459	2,780,214
18	Coal Combustion Residual (CCR) Rule - Demand	3,100	3,158	3,193	3,211	3,251	3,276	3,233	3,232	3,231	3,228	3,227	3,226	38,566
2	Total Investment Projects - Recoverable Costs	$2,131,692	$2,128,339	$2,126,311	$2,125,300	$2,129,438	$2,141,818	$2,129,593	$2,135,829	$2,157,155	$2,184,236	$2,218,995	$2,259,900	$25,868,608
3	Recoverable Costs Allocated to Energy	1,682,749	1,678,133	1,672,788	1,666,638	1,660,824	1,655,420	1,632,795	1,627,710	1,622,665	1,617,036	1,611,956	1,607,211	19,735,928
	Recoverable Costs Allocated to Distribution Demand	106	106	105	105	105	105	104	104	103	103	102	102	1,250
4	Recoverable Costs Allocated to Demand - Production - Base	74,739	77,361	82,038	88,530	99,837	118,976	132,317	144,984	172,700	206,752	247,937	294,932	1,741,103
	Recoverable Costs Allocated to Demand - Production - Intermediate	209,206	208,515	207,815	207,116	206,418	205,720	204,391	203,693	202,998	202,302	201,604	200,910	2,460,690
	Recoverable Costs Allocated to Demand - Production - Peaking	164,892	164,224	163,565	162,911	162,254	161,597	159,986	159,338	158,689	158,043	157,396	156,745	1,929,638
5	Retail Energy Jurisdictional Factor	0.96770	0.96390	0.95790	0.92910	0.92670	0.94150	0.93930	0.93370	0.94560	0.94270	0.95880	0.95280	
	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)	1,628,396	1,617,553	1,602,364	1,548,474	1,539,086	1,558,578	1,533,685	1,519,793	1,534,392	1,524,380	1,545,544	1,531,351	18,683,595
	Jurisdictional Demand Recoverable Costs - Distribution (B)	106	106	105	105	105	105	104	104	103	103	102	102	1,245
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	69,421	71,857	76,201	82,231	92,734	110,511	122,903	134,668	160,412	192,042	230,296	273,948	1,617,224
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	152,099	151,597	151,088	150,580	150,072	149,565	148,599	148,091	147,586	147,080	146,572	146,068	1,788,995
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	158,171	157,530	156,898	156,271	155,640	155,010	153,465	152,843	152,221	151,601	150,980	150,356	1,850,986
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$2,008,193	$1,998,642	$1,986,655	$1,937,659	$1,937,636	$1,973,768	$1,958,754	$1,955,499	$1,994,714	$2,015,205	$2,073,494	$2,101,824	$23,942,044

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 2017 - December 2017

Docket No. 20180007-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: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline - Intermediate (Project 3.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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	33,952	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			$33,952	$33,952	$33,952	$33,952	$33,952	$33,952	$0	$0	$0	$0	$0	$0	$0	
3	Less: Accumulated Depreciation			(9,973)	(10,026)	(10,079)	(10,132)	(10,185)	(10,238)	23,662	0	0	0	0	0	0	
3a	Regulatory Asset Balance (G)			1,571,427	1,522,320	1,473,213	1,424,106	1,374,999	1,325,892	1,276,784	1,250,429	1,200,412	1,150,395	1,100,378	1,050,361	1,000,345	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,595,407	$1,546,246	$1,497,086	$1,447,926	$1,398,766	$1,349,606	$1,300,446	$1,250,429	$1,200,412	$1,150,396	$1,100,379	$1,050,362	$1,000,345	
6	Average Net Investment				$1,570,827	$1,521,666	$1,472,506	$1,423,346	$1,374,186	$1,325,026	$1,275,438	$1,225,421	$1,175,404	$1,125,387	$1,075,370	$1,025,353	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		2,450	2,374	2,297	2,220	2,144	2,067	2,145	2,060	1,976	1,892	1,808	1,724	25,157
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		10,372	10,048	9,723	9,399	9,074	8,749	8,127	7,808	7,490	7,171	6,852	6,534	101,347
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				53	53	53	53	53	53	0	0	0	0	0	0	318
	b. Amortization (G)				49,107	49,107	49,107	49,107	49,107	49,107	50,017	50,017	50,017	50,017	50,017	50,017	594,746
	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)				28	28	28	28	28	28	0	0	0	0	0	0	168
	e. Other (A)				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$62,010	$61,610	$61,208	$60,807	$60,406	$60,004	$60,289	$59,885	$59,483	$59,080	$58,677	$58,275	721,736
	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				$62,010	$61,610	$61,208	$60,807	$60,406	$60,004	$60,289	$59,885	$59,483	$59,080	$58,677	$58,275	721,736
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)				45,083	44,792	44,500	44,209	43,917	43,625	43,832	43,538	43,246	42,953	42,660	42,368	524,723
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$45,083	$44,792	$44,500	$44,209	$43,917	$43,625	$43,832	$43,538	$43,246	$42,953	$42,660	$42,368	$524,723

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). 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 2016 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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			$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	$9,235,204	
3	Less: Accumulated Depreciation			(2,737,036)	(2,765,104)	(2,793,172)	(2,821,240)	(2,849,309)	(2,877,377)	(2,905,442)	(2,933,510)	(2,961,578)	(2,989,645)	(3,017,713)	(3,045,781)	(3,073,848)	
3a	Regulatory Asset Balance (G)			1,234,100	1,188,393	1,142,686	1,096,979	1,051,272	1,005,565	959,858	914,151	868,444	822,737	777,030	731,323	685,616	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$7,732,268	$7,658,493	$7,584,718	$7,510,943	$7,437,167	$7,363,392	$7,289,620	$7,215,845	$7,142,070	$7,068,296	$6,994,521	$6,920,746	$6,846,972	
6	Average Net Investment				$7,695,381	$7,621,605	$7,547,830	$7,474,055	$7,400,280	$7,326,506	$7,252,732	$7,178,958	$7,105,183	$7,031,408	$6,957,634	$6,883,859	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		12,008	11,889	11,772	11,658	11,543	11,428	12,195	12,071	11,948	11,823	11,700	11,575	141,610
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		50,822	50,328	49,839	49,353	48,866	48,378	46,216	45,745	45,273	44,805	44,335	43,863	567,823
	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	336,828
	b. Amortization (G)			45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	548,484
	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	94,512
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$144,482	$143,869	$143,263	$142,663	$142,061	$141,458	$140,063	$139,468	$138,873	$138,280	$137,687	$137,090	1,689,257	
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$144,482	$143,869	$143,263	$142,663	$142,061	$141,458	$140,063	$139,468	$138,873	$138,280	$137,687	$137,090	1,689,257	
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)			138,593	138,005	137,424	136,848	136,271	135,692	134,354	133,783	133,213	132,644	132,075	131,502	1,620,403	
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$138,593	$138,005	$137,424	$136,848	$136,271	$135,692	$134,354	$133,783	$133,213	$132,644	$132,075	$131,502	$1,620,403	

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).

(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 2016 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

(G) Project 4.1a amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.

DUKE ENERGY FLORIDA, LLC
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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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			63,617	60,585	57,553	54,521	51,489	48,457	45,425	42,393	39,361	36,329	33,297	30,265	27,233	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,462,656	$2,459,624	$2,456,592	$2,453,560	$2,450,528	$2,447,496	$2,444,464	$2,441,432	$2,438,400	$2,435,368	$2,432,336	$2,429,304	$2,426,272	
6	Average Net Investment				$2,461,140	$2,458,108	$2,455,076	$2,452,044	$2,449,012	$2,445,980	$2,442,948	$2,439,916	$2,436,884	$2,433,852	$2,430,820	$2,427,788	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		3,839	3,835	3,830	3,824	3,820	3,815	4,108	4,103	4,097	4,092	4,087	4,082	47,532
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		16,251	16,231	16,211	16,191	16,171	16,151	15,567	15,547	15,528	15,509	15,489	15,470	190,316
	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)				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
9	Total System Recoverable Expenses (Lines 7 + 8)				$23,451	$23,427	$23,402	$23,376	$23,352	$23,327	$23,036	$23,011	$22,986	$22,962	$22,937	$22,913	278,180
	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				$23,451	$23,427	$23,402	$23,376	$23,352	$23,327	$23,036	$23,011	$22,986	$22,962	$22,937	$22,913	278,180
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)				21,782	21,760	21,737	21,713	21,691	21,667	21,397	21,374	21,351	21,328	21,305	21,283	258,387
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$21,782	$21,760	$21,737	$21,713	$21,691	$21,667	$21,397	$21,374	$21,351	$21,328	$21,305	$21,283	$258,387

Notes:
(A) N/A
(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).
(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 2016 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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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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(66,486)	(67,011)	(67,536)	(68,061)	(68,586)	(69,111)	(69,636)	(70,161)	(70,686)	(71,211)	(71,736)	(72,261)	(72,786)	
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)			$223,812	$223,287	$222,762	$222,237	$221,712	$221,187	$220,662	$220,137	$219,612	$219,087	$218,562	$218,037	$217,512	
6	Average Net Investment				$223,549	$223,024	$222,499	$221,974	$221,449	$220,924	$220,399	$219,874	$219,349	$218,824	$218,299	$217,774	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		349	348	347	346	345	345	371	370	369	368	367	366	4,291
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		1,476	1,473	1,469	1,466	1,462	1,459	1,404	1,401	1,398	1,394	1,391	1,388	17,181
	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)				$2,555	$2,551	$2,546	$2,542	$2,537	$2,534	$2,505	$2,501	$2,497	$2,492	$2,488	$2,484	30,232
	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				$2,555	$2,551	$2,546	$2,542	$2,537	$2,534	$2,505	$2,501	$2,497	$2,492	$2,488	$2,484	30,232
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)				1,858	1,855	1,851	1,848	1,844	1,842	1,821	1,818	1,815	1,812	1,809	1,806	21,980
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,858	$1,855	$1,851	$1,848	$1,844	$1,842	$1,821	$1,818	$1,815	$1,812	$1,809	$1,806	$21,980

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).

(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 2016 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

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SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0158150 SO2 Emission Allowance Inventory			$3,339,238	$3,335,778	$3,332,862	$3,330,366	$3,327,411	$3,324,542	$3,321,383	$3,318,496	$3,315,814	$3,312,590	$3,309,960	$3,299,780	$3,296,898	$3,296,898
	b. 0254020 Auctioned SO2 Allowance			(4,282)	(3,985)	(3,688)	(3,391)	(3,058)	(2,752)	(2,446)	(2,140)	(1,834)	(1,528)	(1,222)	(916)	(610)	($610)
	c. 0158170 NOx Emission Allowance Inventory (G)			75,394	71,816	71,816	71,816	71,816	71,816	44,818	0	0	0	0	0	0	0
	d. Other NOX Reg Asset (F)			3,629,156	3,326,727	3,024,297	2,721,867	2,419,438	2,117,008	1,814,578	1,556,966	1,245,573	934,180	622,787	311,393	(0)	(0)
2	Total Working Capital			$7,039,505	$6,730,335	$6,425,286	$6,120,658	$5,815,606	$5,510,614	$5,178,333	$4,873,323	$4,559,554	$4,245,242	$3,931,525	$3,610,258	$3,296,289	$3,296,289
3	Average Net Investment				$6,884,920	$6,577,811	$6,272,972	$5,968,132	$5,663,110	$5,344,474	$5,025,828	$4,716,439	$4,402,398	$4,088,383	$3,770,891	$3,453,273	
4	Return on Average Net Working Capital Balance (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		10,739	10,260	9,785	9,309	8,834	8,336	8,452	7,931	7,403	6,875	6,341	5,807	100,072
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		45,462	43,434	41,422	39,409	37,395	35,290	32,023	30,052	28,051	26,050	24,027	22,003	404,618
5	Total Return Component (B)				$56,201	$53,694	$51,207	$48,718	$46,229	$43,626	$40,475	$37,983	$35,454	$32,925	$30,368	$27,810	504,690
6	Expense Dr (Cr)																
	a. 0509030 SO_2 Allowance Expense				$3,459	$2,916	$2,496	$2,956	$2,869	$3,160	$2,886	$2,682	$3,225	$2,630	$10,179	$2,882	$42,339
	b. 0407426 Amortization Expense				($297)	($297)	($297)	($333)	($306)	($306)	($306)	($306)	($306)	($306)	($306)	($306)	(3,673)
	c. 0509212 NOx Allowance Expense				$3,578	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	3,578
	d. Other (G)				$0	$0	$0	$0	$0	($28,002)	$0	$0	$0	$0	$0	$0	(28,002)
7	Net Expense (C)				6,740	2,619	2,198	2,622	2,563	(25,148)	2,580	2,376	2,919	2,324	9,873	2,576	14,242
8	Amortization of NOx CAIR Emission Allowances (F)				302,430	302,430	302,430	302,430	302,430	302,430	302,430	311,393	311,393	311,393	311,393	311,393	3,673,975
9	Total System Recoverable Expenses (Lines 5 + 7 + 8)				$365,371	$358,743	$355,835	$353,770	$351,221	$320,907	$345,485	$351,752	$349,766	$346,642	$351,635	$341,779	4,192,907
	a. Recoverable Costs Allocated to Energy				62,941	56,313	53,405	51,340	48,792	18,478	43,055	40,359	38,373	35,249	40,241	30,386	518,932
	b. Recoverable Costs Allocated to Demand				$302,430	$302,430	$302,430	$302,430	$302,430	$302,430	$302,430	$311,393	$311,393	$311,393	$311,393	$311,393	3,673,975
10	Energy Jurisdictional Factor				0.96770	0.96390	0.95790	0.92910	0.92670	0.94150	0.93930	0.93370	0.94560	0.94270	0.95880	0.95280	
11	NOx Regulatory Asset Energy Factor (12/2014) (F)				0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	0.97930	
12	Retail Energy-Related Recoverable Costs (D)				$60,908	$54,280	$51,157	$47,700	$45,215	$17,397	$40,442	$37,683	$36,285	$33,229	$38,584	$28,952	491,832
13	Retail Demand-Related Recoverable Costs (E)				$296,169	$296,169	$296,169	$296,169	$296,169	$296,169	$296,169	$304,947	$304,947	$304,947	$304,947	$304,947	3,597,923
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$357,077	$350,450	$347,326	$343,870	$341,385	$313,566	$336,611	$342,631	$341,233	$338,177	$343,531	$333,899	$4,089,755

Notes:

(A) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).

(B) Line 5 is reported on Capital Schedule

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

(D) Line 9a x Line 10

(E) Line 9b x Line 11

(F) Unusable NOx emission allowances due to expiration of Clean Air Interstate Rile (CAIR) on 12/31/14 replaced by Cross State Air Pollution Rule (CSAPR) on 1/1/15. DEF is treating these costs as a regulatory asset and amortizing these costs over 3 years consistent with Order No. PSC-2011-0553-FOF-EI.

(G) June 2017 DEF sold $26,998 of Seasonal NOx inventory and made a gain on the sale of of $28,002, for a net proceed of $55,000.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
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Duke Energy Florida
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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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,843	$16,177	$620,288	$663,307
	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	26,843	43,020	663,307	
5	Net Investment (Lines 2 + 3 + 4)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,843	$43,020	$663,307	
6	Average Net Investment				$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,421	$34,931	$353,164	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		0	0	0	0	0	0	0	0	0	23	59	594	676
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		0	0	0	0	0	0	0	0	0	86	223	2,250	2,559
	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)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$109	$282	$2,844	3,235
	a. Recoverable Costs Allocated to Energy			0	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	$109	$282	$2,844	3,235
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			0.92885	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	$0
13	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	101	262	2,642	3,005
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$101	$262	$2,642	$3,005

Notes:
(A) N/A
(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).
(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 2016 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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Docket No. 20180007-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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			$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	$1,802,096	
3	Less: Accumulated Depreciation			(369,873)	(373,287)	(376,701)	(380,115)	(383,529)	(386,943)	(390,357)	(393,771)	(397,185)	(400,599)	(404,013)	(407,427)	(410,841)	
3a	Regulatory Asset Balance (G)			87,069	83,845	80,620	77,395	74,170	70,945	67,721	64,496	61,271	58,046	54,822	51,597	48,372	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,519,293	$1,512,654	$1,506,015	$1,499,377	$1,492,738	$1,486,099	$1,479,460	$1,472,821	$1,466,183	$1,459,544	$1,452,905	$1,446,266	$1,439,627	
6	Average Net Investment				$1,515,974	$1,509,335	$1,502,696	$1,496,057	$1,489,418	$1,482,780	$1,476,141	$1,469,502	$1,462,863	$1,456,224	$1,449,586	$1,442,947	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		2,365	2,354	2,344	2,334	2,323	2,313	2,482	2,471	2,460	2,449	2,437	2,426	28,758
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		10,010	9,966	9,923	9,879	9,835	9,791	9,406	9,364	9,321	9,279	9,237	9,194	115,205
	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	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	38,698
	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)				$20,410	$20,355	$20,302	$20,248	$20,193	$20,139	$19,923	$19,870	$19,816	$19,763	$19,709	$19,655	240,381
	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				$20,410	$20,355	$20,302	$20,248	$20,193	$20,139	$19,923	$19,870	$19,816	$19,763	$19,709	$19,655	240,381
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)				19,578	19,525	19,474	19,422	19,370	19,318	19,111	19,060	19,008	18,957	18,905	18,854	230,583
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$19,578	$19,525	$19,474	$19,422	$19,370	$19,318	$19,111	$19,060	$19,008	$18,957	$18,905	$18,854	$230,583

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).

(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 2016 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

(G) Project 7.2g is being treated as a regulatory asset and is being amortized over 3 years consistent with Order No. PSC-2016-0535-FOF-EI.

DUKE ENERGY FLORIDA, LLC
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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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$123,975	$343,221	$718,449	$822,279	$1,873,819	$2,791,442	$936,537	$2,246,455	$4,659,175	$3,792,093	$6,415,311	$4,641,583	$29,364,339
	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			$3,930,012	$3,930,012	$3,930,012	$3,930,012	$3,930,012	$3,930,012	$3,930,012	$3,930,012	$3,930,012	$3,930,012	$3,930,012	$3,930,012	$3,930,012	
3	Less: Accumulated Depreciation			($185,424)	(193,010)	(200,596)	(208,182)	(215,768)	(223,354)	(230,940)	(238,526)	(246,112)	(253,698)	(261,284)	(268,870)	(276,456)	
4	CWIP - AFUDC-Interest Bearing			905,951	1,029,927	1,373,148	2,091,596	2,913,875	4,787,695	7,579,137	8,515,673	10,762,129	15,421,304	19,213,397	25,628,708	30,270,290	
5	Net Investment (Lines 2 + 3 + 4)			$4,650,540	$4,766,929	$5,102,564	$5,813,427	$6,628,120	$8,494,353	$11,278,209	$12,207,160	$14,446,029	$19,097,618	$22,882,125	$29,289,850	$33,923,847	
6	Average Net Investment				$4,714,669	$4,934,747	$5,457,996	$6,220,773	$7,561,236	$9,886,281	$11,742,685	$13,326,595	$16,771,824	$20,989,872	$26,085,988	$31,606,849	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		7,345	7,675	8,514	9,705	11,794	15,420	19,744	22,407	28,200	35,293	43,862	53,144	263,103
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		31,093	32,585	36,040	41,077	49,929	65,281	74,825	84,917	106,869	133,748	166,220	201,398	1,023,982
	c. Other (F)				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	91,032
	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	558	558	558	558	558	558	558	558	558	558	558	6,696
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$46,582	$48,404	$52,698	$58,926	$69,867	$88,845	$102,713	$115,468	$143,213	$177,185	$218,226	$262,686	1,384,813
	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				$46,582	$48,404	$52,698	$58,926	$69,867	$88,845	$102,713	$115,468	$143,213	$177,185	$218,226	$262,686	1,384,813
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)				43,268	44,960	48,949	54,733	64,896	82,524	95,405	107,252	133,023	164,578	202,699	243,996	1,286,284
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$43,268	$44,960	$48,949	$54,733	$64,896	$82,524	$95,405	$107,252	$133,023	$164,578	$202,699	$243,996	$1,286,284

Notes:
(A) N/A
(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).
(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 2016 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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0154401 Ammonia Inventory			$72,841	$99,762	$74,577	$71,646	$177,154	$145,701	$122,295	$46,701	$168,388	$97,064	$44,291	$16,708	$9,781	9,781
	b. 0154200 Limestone Inventory (F)			1,312,683	1,361,580	1,430,508	1,326,477	1,067,096	1,074,421	1,071,753	1,044,557	1,018,671	1,005,481	1,009,430	1,095,939	1,137,114	1,137,114
2	Total Working Capital			$1,385,523	1,461,342	1,505,086	1,398,123	1,244,250	1,220,122	1,194,048	1,091,258	1,187,059	1,102,545	1,053,721	1,112,647	1,146,895	1,146,895
3	Average Net Investment				1,423,433	1,483,214	1,451,604	1,321,186	1,232,186	1,207,085	1,142,653	1,139,158	1,144,802	1,078,133	1,083,184	1,129,771	
4	Return on Average Net Working Capital Balance (A)	Jan-Jun	Jul-Dec														
	a. Debt Component (F)	1.87%	2.02%		2,220	2,314	2,264	2,061	1,922	1,883	1,921	1,915	1,925	1,813	1,821	1,900	$23,959
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		9,399	9,794	9,585	8,724	8,136	7,971	7,281	7,259	7,295	6,870	6,902	7,199	96,415
5	Total Return Component (B)				11,619	12,108	11,849	10,785	10,058	9,854	9,202	9,174	9,220	8,683	8,723	9,099	120,374
6	Expense Dr (Cr)																
	a. 502030 Ammonia Expense				371,516	359,481	346,062	304,664	384,633	406,494	367,992	274,597	410,823	397,169	27,583	139,571	3,790,585
	b. 502040 Limestone Expense				484,975	462,864	686,423	701,170	767,805	622,093	511,351	634,688	526,517	501,080	16,363	219,357	6,134,685
	c. 502050 Dibasic Acid Expense				0	0	0	0	0	47,967	0	0	0	0	0	26,087	74,054
	d. 502070 Gypsum Disposal/Sale				165,376	186,548	205,744	211,896	261,364	273,988	158,726	8,725	156,220	158,940	15,182	60,243	1,862,952
	e. 502040 Hydrated Lime Expense				273,745	275,976	297,922	315,374	387,326	365,867	333,025	378,098	306,400	280,454	20,001	115,509	3,349,697
	f. 502300 Caustic Expense				0	0	0	0	0	75,950	0	0	0	0	0	104,175	180,125
7	Net Expense (C)				1,295,612	1,284,869	1,536,151	1,533,104	1,801,128	1,792,358	1,371,095	1,296,107	1,399,960	1,337,643	79,129	664,942	15,392,099
8	Total System Recoverable Expenses (Lines 5 + 7)				$1,307,231	$1,296,977	$1,548,000	$1,543,889	$1,811,186	$1,802,212	$1,380,297	$1,305,281	$1,409,180	$1,346,326	$87,852	$674,041	$15,512,473
	a. Recoverable Costs Allocated to Energy				1,307,231	1,296,977	1,548,000	1,543,889	1,811,186	1,802,212	1,380,297	1,305,281	1,409,180	1,346,326	87,852	674,041	$15,512,473
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Energy Jurisdictional Factor				0.96770	0.96390	0.95790	0.92910	0.92670	0.94150	0.93930	0.93370	0.94560	0.94270	0.95880	0.95280	
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)				$1,265,008	$1,250,156	$1,482,829	$1,434,428	$1,678,426	$1,696,783	$1,296,513	$1,218,741	$1,332,521	$1,269,181	$84,233	$642,226	$14,651,044
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)				$1,265,008	$1,250,156	$1,482,829	$1,434,428	$1,678,426	$1,696,783	$1,296,513	$1,218,741	$1,332,521	$1,269,181	$84,233	$642,226	$14,651,044

Notes:

(A) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).
(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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Docket No. 20180007-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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			($3,002)	(3,031)	(3,060)	(3,089)	(3,118)	(3,147)	(3,176)	(3,205)	(3,234)	(3,263)	(3,292)	(3,321)	(3,350)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$8,322	$8,293	$8,264	$8,235	$8,206	$8,177	$8,148	$8,119	$8,090	$8,061	$8,032	$8,003	$7,974	
6	Average Net Investment				$8,308	$8,279	$8,250	$8,221	$8,192	$8,163	$8,134	$8,105	$8,076	$8,047	$8,018	$7,989	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		13	13	13	13	13	13	14	14	14	14	13	13	160
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		55	55	54	54	54	54	52	52	51	51	51	51	634
	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)				$106	$106	$105	$105	$105	$105	$104	$104	$103	$103	$102	$102	1,250
	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				$106	$106	$105	$105	$105	$105	$104	$104	$103	$103	$102	$102	1,250
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)				106	106	105	105	105	105	104	104	103	103	102	102	1,245
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$106	$106	$105	$105	$105	$105	$104	$104	$103	$103	$102	$102	$1,245

Notes:
(A) N/A
(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).
(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 2016 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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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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			($38,896)	(39,192)	(39,488)	(39,784)	(40,080)	(40,376)	(40,672)	(40,968)	(41,264)	(41,560)	(41,856)	(42,152)	(42,448)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$130,045	$129,749	$129,453	$129,157	$128,861	$128,565	$128,269	$127,973	$127,677	$127,381	$127,085	$126,789	$126,493	
6	Average Net Investment				$129,897	$129,601	$129,305	$129,009	$128,713	$128,417	$128,121	$127,825	$127,529	$127,233	$126,937	$126,641	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		203	202	202	201	201	200	215	215	214	214	213	213	2,493
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		858	856	854	852	850	848	816	815	813	811	809	807	9,989
	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)				$1,478	$1,475	$1,473	$1,470	$1,468	$1,465	$1,448	$1,447	$1,444	$1,442	$1,439	$1,437	17,486
	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				$1,478	$1,475	$1,473	$1,470	$1,468	$1,465	$1,448	$1,447	$1,444	$1,442	$1,439	$1,437	17,486
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - 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)				1,373	1,370	1,368	1,365	1,364	1,361	1,345	1,344	1,341	1,339	1,337	1,335	16,242
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,373	$1,370	$1,368	$1,365	$1,364	$1,361	$1,345	$1,344	$1,341	$1,339	$1,337	$1,335	$16,242

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).

(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 2016 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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Docket No. 20180007-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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			($24,221)	(24,424)	(24,627)	(24,830)	(25,033)	(25,236)	(25,439)	(25,642)	(25,845)	(26,048)	(26,251)	(26,454)	(26,657)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$51,785	$51,582	$51,379	$51,176	$50,973	$50,770	$50,567	$50,364	$50,161	$49,958	$49,755	$49,552	$49,349	
6	Average Net Investment				$51,684	$51,481	$51,278	$51,075	$50,872	$50,669	$50,466	$50,263	$50,060	$49,857	$49,654	$49,451	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		81	80	80	80	79	79	85	85	84	84	83	83	983
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		341	340	339	337	336	335	322	320	319	318	316	315	3,938
	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)				$688	$686	$685	$683	$681	$680	$673	$671	$669	$668	$665	$664	8,113
	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				$688	$686	$685	$683	$681	$680	$673	$671	$669	$668	$665	$664	8,113
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)				500	499	498	497	495	494	489	488	486	486	483	483	5,898
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$500	$499	$498	$497	$495	$494	$489	$488	$486	$486	$483	$483	$5,898

Notes:
(A) N/A
(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).
(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 2016 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: Effluent Limitation Guidelines CRN - Base (Project 15.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				($46,334)	$48,510	$43,321	$24,003	$62,189	($22,002)	($14,928)	$0	$0	$0	$0	$0	$94,759
	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			$132,009	85,675	134,185	177,506	201,509	263,698	241,696	226,768	226,768	226,768	226,768	226,768	226,768	
5	Net Investment (Lines 2 + 3 + 4)			$132,009	$85,675	$134,185	$177,506	$201,509	$263,698	$241,696	$226,768	$226,768	$226,768	$226,768	$226,768	$226,768	
6	Average Net Investment				$108,842	$109,930	$155,845	$189,507	$232,603	$252,697	$234,232	$226,768	$226,768	$226,768	$226,768	$226,768	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		76	171	243	296	363	394	394	381	381	381	381	381	3,842
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		52	726	1,029	1,251	1,536	1,669	1,493	1,445	1,445	1,445	1,445	1,445	14,981
	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)				$128	$897	$1,272	$1,547	$1,899	$2,063	$1,887	$1,826	$1,826	$1,826	$1,826	$1,826	18,823
	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				$128	$897	$1,272	$1,547	$1,899	$2,063	$1,887	$1,826	$1,826	$1,826	$1,826	$1,826	18,823
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)				119	833	1,181	1,437	1,764	1,916	1,753	1,696	1,696	1,696	1,696	1,696	17,484
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$119	$833	$1,181	$1,437	$1,764	$1,916	$1,753	$1,696	$1,696	$1,696	$1,696	$1,696	$17,484

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). 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 2016 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 2017 - December 2017

Docket No. 20180007-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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			($860,382)	(896,054)	(931,726)	(967,398)	(1,003,070)	(1,038,742)	(1,074,414)	(1,110,086)	(1,145,758)	(1,181,430)	(1,217,102)	(1,252,774)	(1,288,446)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$11,981,488	$11,945,816	$11,910,144	$11,874,472	$11,838,800	$11,803,128	$11,767,456	$11,731,784	$11,696,112	$11,660,440	$11,624,768	$11,589,096	$11,553,424	
6	Average Net Investment				$11,963,652	$11,927,980	$11,892,308	$11,856,636	$11,820,964	$11,785,292	$11,749,620	$11,713,948	$11,678,276	$11,642,604	$11,606,932	$11,571,260	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		18,661	18,606	18,550	18,494	18,439	18,383	19,756	19,696	19,636	19,576	19,516	19,456	228,769
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		78,993	78,763	78,527	78,291	78,056	77,820	74,869	74,641	74,414	74,187	73,959	73,732	916,252
	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)				$143,953	$143,668	$143,376	$143,084	$142,794	$142,502	$140,924	$140,636	$140,349	$140,062	$139,774	$139,487	1,700,609
	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				$143,953	$143,668	$143,376	$143,084	$142,794	$142,502	$140,924	$140,636	$140,349	$140,062	$139,774	$139,487	1,700,609
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)				104,658	104,451	104,239	104,026	103,816	103,603	102,456	102,247	102,038	101,829	101,620	101,411	1,236,394
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$104,658	$104,451	$104,239	$104,026	$103,816	$103,603	$102,456	$102,247	$102,038	$101,829	$101,620	$101,411	$1,236,394

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). 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 2016 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 2017 - December 2017

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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			($109,013)	(115,595)	(122,177)	(128,759)	(135,341)	(141,923)	(148,505)	(155,087)	(161,669)	(168,251)	(174,833)	(181,415)	(187,997)	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$3,581,174	$3,574,592	$3,568,010	$3,561,428	$3,554,846	$3,548,264	$3,541,682	$3,535,100	$3,528,518	$3,521,936	$3,515,354	$3,508,772	$3,502,190	
6	Average Net Investment				$3,577,883	$3,571,301	$3,564,719	$3,558,137	$3,551,555	$3,544,973	$3,538,391	$3,531,809	$3,525,227	$3,518,645	$3,512,063	$3,505,481	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		5,581	5,571	5,560	5,550	5,540	5,530	5,950	5,938	5,927	5,916	5,905	5,894	68,862
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		23,625	23,582	23,538	23,495	23,452	23,408	22,547	22,505	22,463	22,421	22,379	22,337	275,752
	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)				$35,715	$35,662	$35,607	$35,554	$35,501	$35,447	$35,006	$34,952	$34,899	$34,846	$34,793	$34,740	422,726
	a. Recoverable Costs Allocated to Energy				35,715	35,662	35,607	35,554	35,501	35,447	35,006	34,952	34,899	34,846	34,793	34,740	422,726
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.96770	0.96390	0.95790	0.92910	0.92670	0.94150	0.93930	0.93370	0.94560	0.94270	0.95880	0.95280	
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)				$34,562	$34,375	$34,108	$33,034	$32,899	$33,374	$32,881	$32,635	$33,001	$32,850	$33,360	$33,101	400,179
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)				$34,562	$34,375	$34,108	$33,034	$32,899	$33,374	$32,881	$32,635	$33,001	$32,850	$33,360	$33,101	$400,179

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). 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 2016 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 2017 - December 2017

Docket No. 20180007-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: MERCURY & AIR TOXIC STANDARDS (MATS) - ANCLOTE GAS CONVERSION - Energy (Project 17.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			($8,730,694)	(8,973,108)	(9,215,522)	(9,457,936)	(9,700,350)	(9,942,764)	(10,185,178)	(10,427,592)	(10,670,006)	(10,912,420)	(11,154,834)	(11,397,248)	(11,639,662)	
4	CWIP - AFUDC Bearing			($0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)			$125,187,573	$124,945,159	$124,702,745	$124,460,331	$124,217,917	$123,975,503	$123,733,089	$123,490,675	$123,248,261	$123,005,847	$122,763,433	$122,521,019	$122,278,605	
6	Average Net Investment				$125,066,366	$124,823,952	$124,581,538	$124,339,124	$124,096,710	$123,854,296	$123,611,882	$123,369,468	$123,127,054	$122,884,640	$122,642,226	$122,399,812	
7	Return on Average Net Investment (B)		Jan-Jun	Jul-Dec													
	a. Debt Component		1.87%	2.02%	195,083	194,705	194,326	193,948	193,570	193,192	207,843	207,435	207,028	206,620	206,213	205,805	2,405,768
	b. Equity Component Grossed Up For Taxes		7.92%	7.65%	825,835	824,234	822,634	821,033	819,432	817,832	787,655	786,110	784,565	783,021	781,476	779,931	9,633,758
	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)				$1,343,285	$1,341,306	$1,339,327	$1,337,348	$1,335,369	$1,333,391	$1,317,865	$1,315,912	$1,313,960	$1,312,008	$1,310,056	$1,308,103	15,907,924
	a. Recoverable Costs Allocated to Energy				1,343,285	1,341,306	1,339,327	1,337,348	1,335,369	1,333,391	1,317,865	1,315,912	1,313,960	1,312,008	1,310,056	1,308,103	15,907,924
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.96770	0.96390	0.95790	0.92910	0.92670	0.94150	0.93930	0.93370	0.94560	0.94270	0.95880	0.95280	
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)				$1,299,896	$1,292,884	$1,282,941	$1,242,530	$1,237,486	$1,255,387	$1,237,870	$1,228,667	$1,242,480	$1,236,829	$1,256,081	$1,246,360	15,059,412
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)				$1,299,896	$1,292,884	$1,282,941	$1,242,530	$1,237,486	$1,255,387	$1,237,870	$1,228,667	$1,242,480	$1,236,829	$1,256,081	$1,246,360	$15,059,412

Notes:
(A) N/A
(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002).
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 2016 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 2017 - December 2017

Docket No. 20180007-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: MERCURY & AIR TOXIC STANDARDS (MATS) - CRYSTAL RIVER UNITS 1 & 2 - Energy (Project 17.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant				$228,410	0	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			$22,452,664	$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			($1,328,537)	(1,397,768)	(1,466,999)	(1,536,230)	(1,605,461)	(1,674,692)	(1,743,923)	(1,813,154)	(1,882,385)	(1,951,616)	(2,020,847)	(2,090,078)	(2,159,309)	
4	CWIP - Non-Interest Bearing			$228,410	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$21,352,536	$21,283,305	$21,214,074	$21,144,843	$21,075,612	$21,006,381	$20,937,150	$20,867,919	$20,798,688	$20,729,457	$20,660,226	$20,590,996	$20,521,765	
6	Average Net Investment				$21,317,921	$21,248,690	$21,179,459	$21,110,228	$21,040,997	$20,971,766	$20,902,535	$20,833,304	$20,764,073	$20,694,842	$20,625,611	$20,556,380	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		33,254	33,144	33,036	32,928	32,820	32,712	35,146	35,029	34,913	34,797	34,680	34,564	407,023
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		140,765	140,309	139,852	139,395	138,937	138,480	133,191	132,750	132,309	131,867	131,426	130,985	1,630,266
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	3.7000%			69,231	69,231	69,231	69,231	69,231	69,231	69,231	69,231	69,231	69,231	69,231	69,231	830,772
	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)				$235,929	$235,363	$234,798	$234,233	$233,667	$233,102	$230,247	$229,689	$229,132	$228,574	$228,016	$227,459	2,780,214
	a. Recoverable Costs Allocated to Energy				235,929	235,363	234,798	234,233	233,667	233,102	230,247	229,689	229,132	228,574	228,016	227,459	2,780,214
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.96770	0.96390	0.95790	0.92910	0.92670	0.94150	0.93930	0.93370	0.94560	0.94270	0.95880	0.95280	
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)				$228,309	$226,867	$224,913	$217,626	$216,540	$219,466	$216,271	$214,461	$216,668	$215,477	$218,622	$216,723	2,631,943
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)				$228,309	$226,867	$224,913	$217,626	$216,540	$219,466	$216,271	$214,461	$216,668	$215,477	$218,622	$216,723	$2,631,943

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). 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 2016 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 2017 - December 2017

Docket No. 20180007-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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments															
	a. Expenditures/Additions			$6,990	$7,568	$1,074	$3,765	$6,459	$0	$0	$0	$0	$0	$0	$0	$25,856
	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		$97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	
3	Less: Accumulated Depreciation		0	(176)	(352)	(528)	(704)	(880)	(1,056)	(1,232)	(1,408)	(1,584)	(1,760)	(1,936)	(2,112)	
4	CWIP - Non-Interest Bearing		255,573	262,563	270,131	271,205	274,970	281,429	281,429	281,429	281,429	281,429	281,429	281,429	281,429	
5	Net Investment (Lines 2 + 3 + 4)		$353,158	$359,972	$367,364	$368,262	$371,851	$378,134	$377,958	$377,782	$377,606	$377,430	$377,254	$377,078	$376,902	
6	Average Net Investment			$356,565	$363,668	$367,813	$370,057	$374,992	$378,046	$377,870	$377,694	$377,518	$377,342	$377,166	$376,990	
7	Return on Average Net Investment (B)	Jan-Jun Jul-Dec														
	a. Debt Component	1.87% 2.02%		556	567	574	577	585	590	635	635	635	634	634	634	7,256
	b. Equity Component Grossed Up For Taxes	7.92% 7.65%		2,354	2,401	2,429	2,444	2,476	2,496	2,408	2,407	2,406	2,404	2,403	2,402	29,030
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.1695%		176	176	176	176	176	176	176	176	176	176	176	176	2,112
	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%		14	14	14	14	14	14	14	14	14	14	14	14	168
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$3,100	$3,158	$3,193	$3,211	$3,251	$3,276	$3,233	$3,232	$3,231	$3,228	$3,227	$3,226	38,566
	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			$3,100	$3,158	$3,193	$3,211	$3,251	$3,276	$3,233	$3,232	$3,231	$3,228	$3,227	$3,226	38,566
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			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)			2,879	2,933	2,966	2,983	3,020	3,043	3,003	3,002	3,001	2,998	2,997	2,996	35,822
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,879	$2,933	$2,966	$2,983	$3,020	$3,043	$3,003	$3,002	$3,001	$2,998	$2,997	$2,996	$35,822

Notes:

(A) N/A

(B) Jan - Jun 2017 Line 6 x 9.80% x 1/12. Jul - Dec 2017 Line 6 x 9.66% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.87% (Jan-Jun) and 4.70% (Jul-Dec), and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). 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 2016 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 2017 - December 2017

Capital Structure and Cost Rates

Form 42-9A

Docket No. 20180007-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	$	4,664,905	46.35%	0.10500	4.867%	7.924%
PS		-	0.00%	0.00000	0.000%	0.000%
LTD		3,327,189	33.06%	0.05470	1.809%	1.809%
STD		373,704	3.71%	0.00580	0.022%	0.022%
CD-Active		182,948	1.82%	0.02300	0.042%	0.042%
CD-Inactive		1,367	0.01%	0.00000	0.000%	0.000%
ADIT		1,674,675	16.64%	0.00000	0.000%	0.000%
FAS 109		(161,369)	-1.60%	0.00000	0.000%	0.000%
ITC		223	0.00%	0.00000	0.000%	0.000%
Total	$	10,063,642	100.00%		6.739%	9.796%
				Total Debt	1.872%	1.872%
				Total Equity	4.867%	7.924%

May 2016 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

Class of Capital	Retail	Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE		$4,711,485,475	44.73%	0.10500	4.697%	7.646%
PS		-	0.00%	0.00000	0.000%	0.000%
LTD		3,931,532,102	37.33%	0.05290	1.975%	1.975%
STD		102,874,989	0.98%	0.00210	0.002%	0.002%
CD-Active		191,024,808	1.81%	0.02260	0.041%	0.041%
CD-Inactive		1,455,315	0.01%	0.00000	0.000%	0.000%
ADIT		1,772,932,910	16.83%	0.00000	0.000%	0.000%
FAS 109		(180,390,549)	-1.71%	0.00000	0.000%	0.000%
ITC		1,967,889	0.02%	0.00000	0.000%	0.000%
Total		$10,532,882,939	100.00%		6.715%	9.664%
				Total Debt	2.018%	2.018%
				Total Equity	4.697%	7.646%

May 2017 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Capital Program Detail

January 2017 - December 2017
Final True-Up
Docket No. 20180007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 16
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF)(DIRECT)
DESCRIPTION: Christopher Menendez

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2017 through December 2017
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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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	33,952	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			$33,952	33,952	33,952	33,952	33,952	33,952	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation			(9,973)	(10,026)	(10,079)	(10,132)	(10,185)	(10,238)	23,662	0	0	0	0	0	0	
3a	Regulatory Asset Balance (C)			0	0	0	0	0	0	0	22,752	21,842	20,932	20,022	19,112	18,203	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$23,980	$23,927	$23,874	$23,821	$23,768	$23,715	$23,662	$22,752	$21,842	$20,932	$20,022	$19,113	$18,203	
6	Average Net Investment				23,953	23,900	23,847	23,794	23,741	23,688	23,207	22,297	21,387	20,477	19,568	18,658	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		37	37	37	37	37	37	39	37	36	34	33	31	432
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		158	158	157	157	157	156	148	142	136	130	125	119	1,743
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.8857%			53	53	53	53	53	53	0	0	0	0	0	0	318
	b. Amortization (C)				0	0	0	0	0	0	910	910	910	910	910	910	5,460
	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			28	28	28	28	28	28	0	0	0	0	0	0	168
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$276	$276	$275	$275	$275	$274	$1,097	$1,089	$1,082	$1,074	$1,068	$1,060	$8,121
	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				$276	$276	$275	$275	$275	$274	$1,097	$1,089	$1,082	$1,074	$1,068	$1,060	$8,121

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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)			834,342	808,269	782,196	756,123	730,050	703,976	677,903	651,830	625,757	599,684	573,610	547,537	521,464	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$834,342	$808,269	$782,196	$756,123	$730,050	$703,976	$677,903	$651,830	$625,757	$599,684	$573,610	$547,537	$521,464	
6	Average Net Investment				821,306	795,232	769,159	743,086	717,013	690,940	664,867	638,793	612,720	586,647	560,574	534,501	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		1,281	1,240	1,200	1,159	1,118	1,078	1,118	1,074	1,030	986	943	899	13,126
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		5,423	5,251	5,079	4,907	4,735	4,562	4,237	4,070	3,904	3,738	3,572	3,406	52,884
	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	26,073	26,073	26,073	26,073	312,878
	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)				$32,777	$32,564	$32,352	$32,139	$31,926	$31,713	$31,428	$31,217	$31,007	$30,797	$30,588	$30,378	$378,888
	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				$32,777	$32,564	$32,352	$32,139	$31,926	$31,713	$31,428	$31,217	$31,007	$30,797	$30,588	$30,378	$378,888

(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 retired June 2017, and 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 2017 through December 2017
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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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)			$636,006	616,130	596,255	576,380	556,505	536,630	516,755	496,879	477,004	457,129	437,254	417,379	397,503	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$636,006	$616,130	$596,255	$576,380	$556,505	$536,630	$516,755	$496,879	$477,004	$457,129	$437,254	$417,379	$397,503	
6	Average Net Investment				626,068	606,193	586,318	566,442	546,567	526,692	506,817	486,942	467,067	447,191	427,316	407,441	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		977	946	915	884	853	822	852	819	785	752	718	685	10,008
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		4,134	4,003	3,872	3,740	3,609	3,478	3,229	3,103	2,976	2,850	2,723	2,596	40,313
	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	19,875	19,875	19,875	19,875	238,502
	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)				$24,986	$24,824	$24,662	$24,499	$24,337	$24,175	$23,956	$23,797	$23,636	$23,477	$23,316	$23,156	$288,823
	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				$24,986	$24,824	$24,662	$24,499	$24,337	$24,175	$23,956	$23,797	$23,636	$23,477	$23,316	$23,156	$288,823

For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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)			$101,079	97,920	94,762	91,603	88,444	85,286	82,127	78,968	75,809	72,651	69,492	66,333	63,175	
4	CWIP - Non-Interest Bearing			$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$101,079	$97,920	$94,762	$91,603	$88,444	$85,286	$82,127	$78,968	$75,809	$72,651	$69,492	$66,333	$63,175	
6	Average Net Investment				99,500	96,341	93,182	90,024	86,865	83,706	80,547	77,389	74,230	71,071	67,913	64,754	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		155	150	145	140	135	131	135	130	125	119	114	109	1,588
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		657	636	615	594	574	553	513	493	473	453	433	413	6,407
	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	3,159	3,159	3,159	3,159	37,905
	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)				$3,971	$3,945	$3,919	$3,893	$3,868	$3,843	$3,807	$3,782	$3,757	$3,731	$3,706	$3,681	$45,900
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,971	$3,945	$3,919	$3,893	$3,868	$3,843	$3,807	$3,782	$3,757	$3,731	$3,706	$3,681	$45,900

(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 2017 through December 2017
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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)			1,234,100	1,188,393	1,142,686	1,096,979	1,051,272	1,005,565	959,858	914,151	868,444	822,737	777,030	731,323	685,616	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,234,100	$1,188,393	$1,142,686	$1,096,979	$1,051,272	$1,005,565	$959,858	$914,151	$868,444	$822,737	$777,030	$731,323	$685,616	
6	Average Net Investment				1,211,247	1,165,540	1,119,833	1,074,126	1,028,419	982,712	937,005	891,298	845,591	799,884	754,177	708,470	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		1,889	1,818	1,747	1,675	1,604	1,533	1,575	1,499	1,422	1,345	1,268	1,191	18,566
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		7,998	7,696	7,394	7,093	6,791	6,489	5,971	5,679	5,388	5,097	4,806	4,514	74,916
	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	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	548,484
	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)				$55,594	$55,221	$54,848	$54,475	$54,102	$53,729	$53,253	$52,885	$52,517	$52,149	$51,781	$51,412	$641,966
	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				$55,594	$55,221	$54,848	$54,475	$54,102	$53,729	$53,253	$52,885	$52,517	$52,149	$51,781	$51,412	$641,966

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(336,741)	(340,426)	(344,111)	(347,796)	(351,481)	(355,166)	(358,848)	(362,533)	(366,217)	(369,902)	(373,586)	(377,271)	(380,955)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,137,060	$1,133,375	$1,129,690	$1,126,005	$1,122,320	$1,118,635	$1,114,953	$1,111,268	$1,107,584	$1,103,899	$1,100,215	$1,096,530	$1,092,846	
6	Average Net Investment				1,135,218	1,131,533	1,127,848	1,124,163	1,120,478	1,116,794	1,113,111	1,109,426	1,105,742	1,102,057	1,098,373	1,094,688	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		1,771	1,765	1,759	1,754	1,748	1,742	1,872	1,865	1,859	1,853	1,847	1,841	21,676
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		7,496	7,472	7,447	7,423	7,399	7,374	7,093	7,069	7,046	7,022	6,999	6,975	86,815
	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)				$14,172	$14,142	$14,111	$14,082	$14,052	$14,021	$13,870	$13,839	$13,810	$13,780	$13,751	$13,721	$167,351
	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				$14,172	$14,142	$14,111	$14,082	$14,052	$14,021	$13,870	$13,839	$13,810	$13,780	$13,751	$13,721	$167,351

(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 2017 through December 2017
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(943,799)	(952,938)	(962,077)	(971,216)	(980,355)	(989,494)	(998,633)	(1,007,772)	(1,016,911)	(1,026,050)	(1,035,189)	(1,044,328)	(1,053,467)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$717,865	$708,726	$699,587	$690,448	$681,309	$672,170	$663,031	$653,892	$644,753	$635,614	$626,475	$617,336	$608,197	
6	Average Net Investment				713,296	704,157	695,018	685,879	676,740	667,601	658,462	649,323	640,184	631,045	621,906	612,767	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		1,113	1,098	1,084	1,070	1,056	1,041	1,107	1,092	1,076	1,061	1,046	1,030	12,874
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		4,710	4,650	4,589	4,529	4,469	4,408	4,196	4,137	4,079	4,021	3,963	3,905	51,656
	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)				$16,139	$16,064	$15,989	$15,915	$15,841	$15,765	$15,619	$15,545	$15,471	$15,398	$15,325	$15,251	$188,322
	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				$16,139	$16,064	$15,989	$15,915	$15,841	$15,765	$15,619	$15,545	$15,471	$15,398	$15,325	$15,251	$188,322

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(81,305)	(82,021)	(82,737)	(83,453)	(84,169)	(84,885)	(85,601)	(86,317)	(87,033)	(87,749)	(88,465)	(89,181)	(89,897)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$97,633	$96,917	$96,201	$95,485	$94,769	$94,053	$93,337	$92,621	$91,905	$91,189	$90,473	$89,757	$89,041	
6	Average Net Investment				97,275	96,559	95,843	95,127	94,411	93,695	92,979	92,263	91,547	90,831	90,115	89,399	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		152	151	149	148	147	146	156	155	154	153	152	150	1,813
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		642	638	633	628	623	619	592	588	583	579	574	570	7,269
	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)				$1,650	$1,645	$1,638	$1,632	$1,626	$1,621	$1,604	$1,599	$1,593	$1,588	$1,582	$1,576	$19,354
	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				$1,650	$1,645	$1,638	$1,632	$1,626	$1,621	$1,604	$1,599	$1,593	$1,588	$1,582	$1,576	$19,354

(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 2017 through December 2017
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(198,750)	(200,572)	(202,394)	(204,216)	(206,039)	(207,861)	(209,683)	(211,505)	(213,327)	(215,150)	(216,972)	(218,794)	(220,616)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$531,546	$529,723	$527,901	$526,079	$524,257	$522,435	$520,612	$518,790	$516,968	$515,146	$513,324	$511,501	$509,679	
6	Average Net Investment				530,634	528,812	526,990	525,168	523,346	521,524	519,701	517,879	516,057	514,235	512,413	510,590	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		832	825	822	819	816	813	874	871	868	865	862	859	10,126
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		3,512	3,492	3,480	3,468	3,456	3,444	3,312	3,300	3,288	3,277	3,265	3,253	40,547
	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	0.009930			604	604	604	604	604	604	604	604	604	604	604	604	7,248
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$6,770	$6,743	$6,728	$6,713	$6,698	$6,683	$6,612	$6,597	$6,582	$6,568	$6,553	$6,538	$79,785
	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				$6,770	$6,743	$6,728	$6,713	$6,698	$6,683	$6,612	$6,597	$6,582	$6,568	$6,553	$6,538	$79,785

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(323,928)	(326,780)	(329,632)	(332,484)	(335,336)	(338,188)	(341,040)	(343,892)	(346,744)	(349,596)	(352,448)	(355,300)	(358,152)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$713,271	$710,419	$707,567	$704,715	$701,863	$699,011	$696,159	$693,307	$690,455	$687,603	$684,751	$681,899	$679,047	
6	Average Net Investment				711,845	708,993	706,141	703,289	700,437	697,585	694,733	691,881	689,029	686,177	683,325	680,473	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		1,110	1,106	1,101	1,097	1,093	1,088	1,168	1,163	1,159	1,154	1,149	1,144	13,532
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		4,700	4,682	4,663	4,644	4,625	4,606	4,427	4,409	4,390	4,372	4,354	4,336	54,208
	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)				$9,411	$9,389	$9,365	$9,342	$9,319	$9,295	$9,196	$9,173	$9,150	$9,127	$9,104	$9,081	$110,952
	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				$9,411	$9,389	$9,365	$9,342	$9,319	$9,295	$9,196	$9,173	$9,150	$9,127	$9,104	$9,081	$110,952

(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 2017 through December 2017
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			$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			(633,998)	(641,834)	(649,670)	(657,506)	(665,342)	(673,178)	(681,014)	(688,850)	(696,686)	(704,522)	(712,358)	(720,194)	(728,030)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,982,906	$2,975,070	$2,967,234	$2,959,398	$2,951,562	$2,943,726	$2,935,890	$2,928,054	$2,920,218	$2,912,382	$2,904,546	$2,896,710	$2,888,874	
6	Average Net Investment				2,978,988	2,971,152	2,963,316	2,955,480	2,947,644	2,939,808	2,931,972	2,924,136	2,916,300	2,908,464	2,900,628	2,892,792	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		4,647	4,635	4,622	4,610	4,598	4,586	4,930	4,917	4,904	4,890	4,877	4,864	57,080
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		19,671	19,619	19,567	19,516	19,464	19,412	18,683	18,633	18,583	18,533	18,483	18,433	228,597
	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)				$35,660	$35,596	$35,531	$35,468	$35,404	$35,340	$34,955	$34,892	$34,829	$34,765	$34,702	$34,639	$421,781
	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				$35,660	$35,596	$35,531	$35,468	$35,404	$35,340	$34,955	$34,892	$34,829	$34,765	$34,702	$34,639	$421,781

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			$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			(57,450)	(57,691)	(57,932)	(58,173)	(58,414)	(58,655)	(58,896)	(59,137)	(59,378)	(59,619)	(59,860)	(60,101)	(60,342)	
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)			$83,984	$83,743	$83,502	$83,261	$83,020	$82,779	$82,538	$82,297	$82,056	$81,815	$81,574	$81,333	$81,092	
6	Average Net Investment				83,864	83,623	83,382	83,141	82,900	82,659	82,418	82,177	81,936	81,695	81,454	81,213	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		131	130	130	130	129	129	139	138	138	137	137	137	1,605
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		554	552	551	549	547	546	525	524	522	521	519	517	6,427
	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)				$1,080	$1,077	$1,076	$1,074	$1,071	$1,070	$1,059	$1,057	$1,055	$1,053	$1,051	$1,049	$12,772
	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				$1,080	$1,077	$1,076	$1,074	$1,071	$1,070	$1,059	$1,057	$1,055	$1,053	$1,051	$1,049	$12,772

(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 2017 through December 2017
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	$394,968	
3	Less: Accumulated Depreciation			(161,064)	(162,841)	(164,618)	(166,395)	(168,172)	(169,949)	(171,726)	(173,503)	(175,280)	(177,057)	(178,834)	(180,611)	(182,388)	
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)			$233,904	$232,127	$230,350	$228,573	$226,796	$225,019	$223,242	$221,465	$219,688	$217,911	$216,134	$214,357	$212,580	
6	Average Net Investment				233,015	231,238	229,461	227,684	225,907	224,130	222,353	220,576	218,799	217,022	215,245	213,468	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		363	361	358	355	352	350	374	371	368	365	362	359	4,338
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		1,539	1,527	1,515	1,503	1,492	1,480	1,417	1,406	1,394	1,383	1,372	1,360	17,388
	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				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)				$4,006	$3,992	$3,977	$3,962	$3,948	$3,934	$3,895	$3,881	$3,866	$3,852	$3,838	$3,823	$46,974
	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				$4,006	$3,992	$3,977	$3,962	$3,948	$3,934	$3,895	$3,881	$3,866	$3,852	$3,838	$3,823	$46,974

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			$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			(17,115)	(17,217)	(17,319)	(17,421)	(17,523)	(17,625)	(17,727)	(17,829)	(17,931)	(18,033)	(18,135)	(18,237)	(18,339)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$15,977	$15,875	$15,773	$15,671	$15,569	$15,467	$15,365	$15,263	$15,161	$15,059	$14,957	$14,855	$14,753	
6	Average Net Investment				15,926	15,824	15,722	15,620	15,518	15,416	15,314	15,212	15,110	15,008	14,906	14,804	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		25	25	25	24	24	24	26	26	25	25	25	25	299
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		105	104	104	103	102	102	98	97	96	96	95	94	1,196
	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)				$237	$236	$236	$234	$233	$233	$231	$230	$228	$228	$227	$226	$2,779
	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				$237	$236	$236	$234	$233	$233	$231	$230	$228	$228	$227	$226	$2,779

(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 2017 through December 2017
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			80,732	77,802	74,872	71,942	69,012	66,082	63,152	60,222	57,292	54,362	51,432	48,502	45,572	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,446,680	$2,443,749	$2,440,819	$2,437,889	$2,434,959	$2,432,029	$2,429,099	$2,426,169	$2,423,239	$2,420,309	$2,417,379	$2,414,449	$2,411,519	
6	Average Net Investment				2,445,215	2,442,284	2,439,354	2,436,424	2,433,494	2,430,564	2,427,634	2,424,704	2,421,774	2,418,844	2,415,914	2,412,984	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		3,814	3,810	3,805	3,800	3,796	3,791	4,082	4,077	4,072	4,067	4,062	4,057	47,233
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		16,146	16,127	16,107	16,088	16,069	16,049	15,469	15,450	15,432	15,413	15,394	15,376	189,120
	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)				$23,214	$23,191	$23,166	$23,142	$23,119	$23,094	$22,805	$22,781	$22,758	$22,734	$22,710	$22,687	$275,401
	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				$23,214	$23,191	$23,166	$23,142	$23,119	$23,094	$22,805	$22,781	$22,758	$22,734	$22,710	$22,687	$275,401

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(66,486)	(67,011)	(67,536)	(68,061)	(68,586)	(69,111)	(69,636)	(70,161)	(70,686)	(71,211)	(71,736)	(72,261)	(72,786)	
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)			$223,812	$223,287	$222,762	$222,237	$221,712	$221,187	$220,662	$220,137	$219,612	$219,087	$218,562	$218,037	$217,512	
6	Average Net Investment				223,549	223,024	222,499	221,974	221,449	220,924	220,399	219,874	219,349	218,824	218,299	217,774	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		349	348	347	346	345	345	371	370	369	368	367	366	4,291
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		1,476	1,473	1,469	1,466	1,462	1,459	1,404	1,401	1,398	1,394	1,391	1,388	17,181
	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)				$2,555	$2,551	$2,546	$2,542	$2,537	$2,534	$2,505	$2,501	$2,497	$2,492	$2,488	$2,484	$30,232
	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				$2,555	$2,551	$2,546	$2,542	$2,537	$2,534	$2,505	$2,501	$2,497	$2,492	$2,488	$2,484	$30,232

(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 2017 through December 2017
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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			(38,489)	(38,893)	(39,297)	(39,701)	(40,105)	(40,509)	(40,913)	(41,317)	(41,721)	(42,125)	(42,529)	(42,933)	(43,337)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$123,265	$122,861	$122,457	$122,053	$121,649	$121,245	$120,841	$120,437	$120,033	$119,629	$119,225	$118,821	$118,417	
6	Average Net Investment				123,063	122,659	122,255	121,851	121,447	121,043	120,639	120,235	119,831	119,427	119,023	118,619	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		192	191	191	190	189	189	203	202	201	201	200	199	2,348
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		813	810	807	805	802	799	769	766	764	761	758	756	9,410
	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)				$1,536	$1,532	$1,529	$1,526	$1,522	$1,519	$1,503	$1,499	$1,496	$1,493	$1,489	$1,486	$18,130
	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				$1,536	$1,532	$1,529	$1,526	$1,522	$1,519	$1,503	$1,499	$1,496	$1,493	$1,489	$1,486	$18,130

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			(49,561)	(49,919)	(50,277)	(50,635)	(50,993)	(51,351)	(51,709)	(52,067)	(52,425)	(52,783)	(53,141)	(53,499)	(53,857)	
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)			$225,786	$225,428	$225,070	$224,712	$224,354	$223,996	$223,638	$223,280	$222,922	$222,564	$222,206	$221,848	$221,490	
6	Average Net Investment				225,607	225,249	224,891	224,533	224,175	223,817	223,459	223,101	222,743	222,385	222,027	221,669	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		352	351	351	350	350	349	376	375	375	374	373	373	4,349
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		1,490	1,487	1,485	1,483	1,480	1,478	1,424	1,422	1,419	1,417	1,415	1,412	17,412
	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)				$2,428	$2,424	$2,422	$2,419	$2,416	$2,413	$2,386	$2,383	$2,380	$2,377	$2,374	$2,371	$28,793
	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				$2,428	$2,424	$2,422	$2,419	$2,416	$2,413	$2,386	$2,383	$2,380	$2,377	$2,374	$2,371	$28,793

(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 2017 through December 2017
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			(43,263)	(43,647)	(44,031)	(44,415)	(44,799)	(45,183)	(45,567)	(45,951)	(46,335)	(46,719)	(47,103)	(47,487)	(47,871)	
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)			$155,725	$155,341	$154,957	$154,573	$154,189	$153,805	$153,421	$153,037	$152,653	$152,269	$151,885	$151,501	$151,117	
6	Average Net Investment				155,533	155,149	154,765	154,381	153,997	153,613	153,229	152,845	152,461	152,077	151,693	151,309	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		243	242	241	241	240	240	258	257	256	256	255	254	2,983
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		1,027	1,024	1,022	1,019	1,017	1,014	976	974	971	969	967	964	11,944
	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)				$1,819	$1,815	$1,812	$1,809	$1,806	$1,803	$1,783	$1,780	$1,776	$1,774	$1,771	$1,767	$21,515
	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				$1,819	$1,815	$1,812	$1,809	$1,806	$1,803	$1,783	$1,780	$1,776	$1,774	$1,771	$1,767	$21,515

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			(24,771)	(24,990)	(25,209)	(25,428)	(25,647)	(25,866)	(26,085)	(26,304)	(26,523)	(26,742)	(26,961)	(27,180)	(27,399)	
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)			$62,896	$62,677	$62,458	$62,239	$62,020	$61,801	$61,582	$61,363	$61,144	$60,925	$60,706	$60,487	$60,268	
6	Average Net Investment				62,787	62,568	62,349	62,130	61,911	61,692	61,473	61,254	61,035	60,816	60,597	60,378	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		98	98	97	97	97	96	103	103	103	102	102	102	1,198
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		415	413	412	410	409	407	392	390	389	388	386	385	4,796
	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)				$817	$815	$813	$811	$810	$807	$799	$797	$796	$794	$792	$791	$9,642
	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				$817	$815	$813	$811	$810	$807	$799	$797	$796	$794	$792	$791	$9,642

(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 2017 through December 2017
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			$347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	
3	Less: Accumulated Depreciation			(77,109)	(77,948)	(78,787)	(79,626)	(80,465)	(81,304)	(82,143)	(82,982)	(83,821)	(84,660)	(85,499)	(86,338)	(87,177)	
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)			$270,089	$269,250	$268,411	$267,572	$266,733	$265,894	$265,055	$264,216	$263,377	$262,538	$261,699	$260,860	$260,021	
6	Average Net Investment				269,669	268,830	267,991	267,152	266,313	265,474	264,635	263,796	262,957	262,118	261,279	260,440	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		421	419	418	417	415	414	445	444	442	441	439	438	5,153
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		1,781	1,775	1,770	1,764	1,759	1,753	1,686	1,681	1,676	1,670	1,665	1,660	20,640
	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)				$3,328	$3,320	$3,314	$3,307	$3,300	$3,293	$3,257	$3,251	$3,244	$3,237	$3,230	$3,224	$39,305
	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				$3,328	$3,320	$3,314	$3,307	$3,300	$3,293	$3,257	$3,251	$3,244	$3,237	$3,230	$3,224	$39,305

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			(85,567)	(86,354)	(87,141)	(87,928)	(88,715)	(89,502)	(90,289)	(91,076)	(91,863)	(92,650)	(93,437)	(94,224)	(95,011)	
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)			$264,017	$263,230	$262,443	$261,656	$260,869	$260,082	$259,295	$258,508	$257,721	$256,934	$256,147	$255,360	$254,573	
6	Average Net Investment				263,623	262,836	262,049	261,262	260,475	259,688	258,901	258,114	257,327	256,540	255,753	254,966	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		411	410	409	408	406	405	435	434	433	431	430	429	5,041
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		1,741	1,736	1,730	1,725	1,720	1,715	1,650	1,645	1,640	1,635	1,630	1,625	20,192
	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)				$3,187	$3,181	$3,174	$3,168	$3,161	$3,155	$3,120	$3,114	$3,108	$3,101	$3,095	$3,089	$37,653
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$3,187	$3,181	$3,174	$3,168	$3,161	$3,155	$3,120	$3,114	$3,108	$3,101	$3,095	$3,089	$37,653

(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 2017 through December 2017
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	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			$0	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	0	
3a	Regulatory Asset Balance (B)			87,069	83,845	80,620	77,395	74,170	70,945	67,721	64,496	61,271	58,046	54,822	51,597	48,372	
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)			$87,069	$83,845	$80,620	$77,395	$74,170	$70,945	$67,721	$64,496	$61,271	$58,046	$54,822	$51,597	$48,372	
6	Average Net Investment				85,457	82,232	79,007	75,783	72,558	69,333	66,108	62,884	59,659	56,434	53,209	49,984	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		133	128	123	118	113	108	111	106	100	95	89	84	1,308
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		564	543	522	500	479	458	421	401	380	360	339	318	5,285
	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	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	38,698
	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)				$3,922	$3,896	$3,870	$3,843	$3,817	$3,791	$3,757	$3,732	$3,705	$3,680	$3,653	$3,627	$45,291
	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				$3,922	$3,896	$3,870	$3,843	$3,817	$3,791	$3,757	$3,732	$3,705	$3,680	$3,653	$3,627	$45,291

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(51,114)	(51,537)	(51,960)	(52,383)	(52,806)	(53,229)	(53,652)	(54,075)	(54,498)	(54,921)	(55,344)	(55,767)	(56,190)	
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)			$330,446	$330,023	$329,600	$329,177	$328,754	$328,331	$327,908	$327,485	$327,062	$326,639	$326,216	$325,793	$325,370	
6	Average Net Investment				330,234	329,811	329,388	328,965	328,542	328,119	327,696	327,273	326,850	326,427	326,004	325,581	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		515	514	514	513	512	512	551	550	550	549	548	547	6,375
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		2,181	2,178	2,175	2,172	2,169	2,167	2,088	2,085	2,083	2,080	2,077	2,075	25,530
	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)				$3,375	$3,371	$3,368	$3,364	$3,360	$3,358	$3,318	$3,314	$3,312	$3,308	$3,304	$3,301	$40,053
	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				$3,375	$3,371	$3,368	$3,364	$3,360	$3,358	$3,318	$3,314	$3,312	$3,308	$3,304	$3,301	$40,053

(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 2017 through December 2017
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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(75,953)	(80,377)	(84,801)	(89,225)	(93,649)	(98,073)	(102,497)	(106,921)	(111,345)	(115,769)	(120,193)	(124,617)	(129,041)	
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)			$2,073,147	$2,068,723	$2,064,299	$2,059,875	$2,055,451	$2,051,027	$2,046,603	$2,042,179	$2,037,755	$2,033,331	$2,028,907	$2,024,483	$2,020,059	
6	Average Net Investment				2,070,935	2,066,511	2,062,087	2,057,663	2,053,239	2,048,815	2,044,391	2,039,967	2,035,543	2,031,119	2,026,695	2,022,271	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		3,230	3,223	3,217	3,210	3,203	3,196	3,437	3,430	3,423	3,415	3,408	3,400	39,792
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		13,675	13,646	13,616	13,587	13,558	13,529	13,027	12,999	12,970	12,942	12,914	12,886	159,349
	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)				$21,634	$21,598	$21,562	$21,526	$21,490	$21,454	$21,193	$21,158	$21,122	$21,086	$21,051	$21,015	$255,889
	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				$21,634	$21,598	$21,562	$21,526	$21,490	$21,454	$21,193	$21,158	$21,122	$21,086	$21,051	$21,015	$255,889

For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$123,975	$343,221	$718,449	$822,279	$1,873,819	$2,791,442	$936,537	$2,246,455	$4,659,175	$3,792,093	$6,415,311	$4,641,583	$29,364,339
	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			$614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	
3	Less: Accumulated Depreciation			(24,923)	(25,683)	(26,443)	(27,203)	(27,963)	(28,723)	(29,483)	(30,243)	(31,003)	(31,763)	(32,523)	(33,283)	(34,043)	
4	CWIP - Non-Interest Bearing			905,951	1,029,927	1,373,148	2,091,596	2,913,875	4,787,695	7,579,137	8,515,673	10,762,129	15,421,304	19,213,397	25,628,708	30,270,290	
5	Net Investment (Lines 2 + 3 + 4)			$1,495,038	$1,618,253	$1,960,714	$2,678,403	$3,499,922	$5,372,981	$8,163,664	$9,099,440	$11,345,136	$16,003,551	$19,794,884	$26,209,434	$30,850,257	
6	Average Net Investment				1,556,646	1,789,484	2,319,559	3,089,163	4,436,452	6,768,322	8,631,552	10,222,288	13,674,343	17,899,217	23,002,159	28,529,846	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		2,428	2,769	3,618	4,819	6,920	10,557	14,513	17,188	22,992	30,096	38,676	47,971	202,547
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		10,279	11,816	15,316	20,398	29,295	44,692	55,000	65,136	87,133	114,054	146,570	181,792	781,481
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.4860%			760	760	760	760	760	760	760	760	760	760	760	760	9,120
	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	87	87	87	87	87	87	87	87	87	87	87	1,044
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$13,554	$15,432	$19,781	$26,064	$37,062	$56,096	$70,360	$83,171	$110,972	$144,997	$186,093	$230,610	$994,192
	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				$13,554	$15,432	$19,781	$26,064	$37,062	$56,096	$70,360	$83,171	$110,972	$144,997	$186,093	$230,610	$994,192

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 2017 through December 2017
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-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(55,201)	(56,562)	(57,923)	(59,284)	(60,645)	(62,006)	(63,367)	(64,728)	(66,089)	(67,450)	(68,811)	(70,172)	(71,533)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$605,797	$604,436	$603,075	$601,714	$600,353	$598,992	$597,631	$596,270	$594,909	$593,548	$592,187	$590,826	$589,465	
6	Average Net Investment				605,117	603,756	602,395	601,034	599,673	598,312	596,951	595,590	594,229	592,868	591,507	590,146	
7	Return on Average Net Investment (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		944	942	940	938	935	933	1,004	1,001	999	997	995	992	11,620
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		3,996	3,987	3,978	3,969	3,960	3,951	3,804	3,795	3,786	3,778	3,769	3,760	46,533
	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)				$6,395	$6,384	$6,373	$6,362	$6,350	$6,339	$6,263	$6,251	$6,240	$6,230	$6,219	$6,207	$75,613
	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				$6,395	$6,384	$6,373	$6,362	$6,350	$6,339	$6,263	$6,251	$6,240	$6,230	$6,219	$6,207	$75,613

For Project: CAIR Crystal River - FGD Common (Project 7.4s) - CR5 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-17	Actual Feb-17	Actual Mar-17	Actual Apr-17	Actual May-17	Actual Jun-17	Actual Jul-17	Actual Aug-17	Actual Sep-17	Actual Oct-17	Actual Nov-17	Actual Dec-17	Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(29,347)	(30,388)	(31,429)	(32,470)	(33,511)	(34,552)	(35,593)	(36,634)	(37,675)	(38,716)	(39,757)	(40,798)	(41,839)	
4	CWIP - Non-Interest Bearing			-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$476,557	$475,516	$474,475	$473,434	$472,393	$471,352	$470,311	$469,270	$468,229	$467,188	$466,147	$465,106	$464,065	
6	Return on Average Net Investment (A)				476,037	474,996	473,955	472,914	471,873	470,832	469,791	468,750	467,709	466,668	465,627	464,586	
7	Return on Average Net Investment	Jan-Jun	Jul-Dec														
	a. Debt Component	1.87%	2.02%		743	741	739	738	736	734	790	788	786	785	783	781	9,144
	b. Equity Component Grossed Up For Taxes	7.92%	7.65%		3,143	3,136	3,130	3,123	3,116	3,109	2,994	2,987	2,980	2,974	2,967	2,960	36,619
	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)				$4,999	$4,990	$4,982	$4,974	$4,965	$4,956	$4,897	$4,888	$4,879	$4,872	$4,863	$4,854	$59,119
	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				$4,999	$4,990	$4,982	$4,974	$4,965	$4,956	$4,897	$4,888	$4,879	$4,872	$4,863	$4,854	$59,119

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 2018 - December 2018
Calculation for the Current Period Actual / Estimated Amount
Actuals for the Period January 2018 - June 2018
Estimates for the Period July 2018 - December 2018

Docket No. 20180007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 17
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF)(DIRECT)
DESCRIPTION: Christopher Menendez

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2018 - December 2018
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period (Form 42-2E, Line 5)	$ 4,287,611
2	Interest Provision (Form 42-2E, Line 6)	156,583
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 2018 to December 2018 (Lines 1 + 2 + 3)	$ 4,444,194

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2018 - December 2018

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$4,325,385	$4,601,370	$4,522,575	$ 4,290,070	$4,441,341	$5,355,200	$6,214,944	$6,482,990	$6,314,636	$5,722,470	$4,834,236	$4,639,470	$61,744,686
2	True-Up Provision (Order No. PSC-2018-0014-FOF-EI)	3,017,507	251,459	251,459	251,459	251,459	251,459	251,459	251,459	251,459	251,459	251,459	251,459	251,459	3,017,507
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		$4,576,844	4,852,829	4,774,034	4,541,529	4,692,799	5,606,659	6,466,402	6,734,449	6,566,095	5,973,929	5,085,695	4,890,929	64,762,193
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5E, Line 9)		$2,622,245	3,078,387	3,502,953	2,169,564	2,628,494	2,233,725	3,206,057	3,137,920	3,107,861	3,459,885	3,480,693	3,471,621	36,099,405
	b. Capital Investment Projects (Form 42-7E, Line 9)		1,917,294	1,921,902	1,948,641	1,983,069	1,977,792	1,989,968	2,032,161	2,067,916	2,104,748	2,131,136	2,152,582	2,147,967	24,375,177
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Total Jurisdictional ECRC Costs		$4,539,539	$5,000,289	$5,451,594	$4,152,633	$4,606,286	$4,223,693	$5,238,218	$5,205,836	$5,212,609	$5,591,021	$5,633,275	$5,619,588	$60,474,582
5	Over/(Under) Recovery (Line 3 - Line 4d)		$37,305	(147,461)	(677,561)	388,896	86,514	1,382,965	1,228,184	1,528,614	1,353,486	382,907	(547,579)	(728,659)	$4,287,611
6	Interest Provision (Form 42-3E, Line 10)		9,811	9,508	9,822	9,901	9,896	11,004	13,105	14,986	16,974	18,019	17,498	16,059	156,583
7	Beginning Balance True-Up & Interest Provision		3,017,507	2,813,164	2,423,752	1,504,555	1,651,893	1,496,844	2,639,354	3,629,184	4,921,325	6,040,325	6,189,793	5,408,253	3,017,507
	a. Deferred True-Up - January 2017 to December 2017 (2017 TU filing dated April 2, 2018)		4,814,791	4,814,791	4,814,791	4,814,791	4,814,791	4,814,791	4,814,791	4,814,791	4,814,791	4,814,791	4,814,791	4,814,791	4,814,791
8	True-Up Collected/(Refunded) (Line 2)		(251,459)	(251,459)	(251,459)	(251,459)	(251,459)	(251,459)	(251,459)	(251,459)	(251,459)	(251,459)	(251,459)	(251,459)	(3,017,507)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		$7,627,955	7,238,543	6,319,346	6,466,684	6,311,635	7,454,145	8,443,975	9,736,116	10,855,117	11,004,584	10,223,044	9,258,985	$9,258,985
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)		$7,627,955	$7,238,543	$6,319,346	$6,466,684	$6,311,635	$7,454,145	8,443,975	$9,736,116	$10,855,117	$11,004,584	$10,223,044	$9,258,985	$9,258,985

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2018 - December 2018

Interest Provision
(in Dollars)

Line	Description	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$7,832,298	$7,627,955	$7,238,543	$6,319,346	$6,466,684	$6,311,635	$7,454,145	$8,443,975	$9,736,116	$10,855,117	$11,004,584	$10,223,044	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	7,618,144	7,229,035	6,309,524	6,456,783	6,301,739	7,443,141	8,430,870	9,721,130	10,838,143	10,986,565	10,205,546	9,242,926	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	15,450,442	14,856,990	13,548,067	12,776,128	12,768,422	13,754,775	15,885,015	18,165,104	20,574,258	21,841,682	21,210,130	19,465,970	
4	Average True-Up Amount (Line 3 x 1/2)	7,725,221	7,428,495	6,774,034	6,388,064	6,384,211	6,877,388	7,942,508	9,082,552	10,287,129	10,920,841	10,605,065	9,732,985	
5	Interest Rate (Last Business Day of Prior Month)	1.58%	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	
6	Interest Rate (Last Business Day of Current Month)	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.04%	3.08%	3.48%	3.71%	3.71%	3.84%	3.96%	3.96%	3.96%	3.96%	3.96%	3.96%	
8	Average Interest Rate (Line 7 x 1/2)	1.520%	1.540%	1.740%	1.855%	1.855%	1.920%	1.980%	1.980%	1.980%	1.980%	1.980%	1.980%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.127%	0.128%	0.145%	0.155%	0.155%	0.160%	0.165%	0.165%	0.165%	0.165%	0.165%	0.165%	
10	Interest Provision for the Month (Line 4 x Line 9)	$9,811	$9,508	$9,822	$9,901	$9,896	$11,004	$13,105	$14,986	$16,974	$18,019	$17,498	$16,059	156,583

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2018 - December 2018

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	$484,949	$397,896	$87,053	22%
	1a	Distribution Substation Environmental Investigation, Remediation and Pollution Prevention	371,361	284,904	86,457	30%
	2	Distribution System Environmental Investigation, Remediation and Pollution Prevention	8,000	15,000	(7,000)	-47%
	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	37,593	25,876	11,717	45%
	6	Phase II Cooling Water Intake 316(b) - Base	232,200	232,200	(0)	0%
	6.a	Phase II Cooling Water Intake 316(b) - Intm	32,989	12,600	20,389	162%
	7.2	CAIR/CAMR - Peaking	0	0	0	0%
	7.4	CAIR/CAMR Crystal River - Base	16,027,287	15,399,946	627,341	4%
	7.4	CAIR/CAMR Crystal River - Energy	17,461,449	17,629,254	(167,805)	-1%
	7.4	CAIR/CAMR Crystal River - A&G	96,243	153,121	(56,878)	-37%
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	495,000	495,000	0	0%
	7.5	Best Available Retrofit Technology (BART) - Energy	0	0	0	0%
	8	Arsenic Groundwater Standard - Base	170,228	150,000	20,228	13%
	9	Sea Turtle - Coastal Street Lighting - Distrib	600	350	250	71%
	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	40,000	0	40,000	100%
	16	National Pollutant Discharge Elimination System (NPDES) - Energy	32,320	32,320	(0)	0%
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	458,901	598,440	(139,539)	-23%
	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	1,496,883	1,548,376	(51,493)	-3%
	18	Coal Combustion Residual (CCR) Rule - Energy	895,851	351,190	544,661	155%
2		Total O&M Activities - Recoverable Costs	$38,341,855	$37,326,472	$1,015,382	3%
3		Recoverable Costs Allocated to Energy	20,917,997	20,680,456	237,541	1%
4		Recoverable Costs Allocated to Demand	$17,423,858	$16,646,016	$777,841	5%

Notes:

Column (1) End of Period Totals on Form 42-5E
Column (2) 2017 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 2018 - December 2018

O&M Activities
(in Dollars)

Line	Description	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	O&M Activities - System													
1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$15,917	$71,800	$43,589	$47,512	$45,491	$29,833	$56,935	$2,788	$72,796	$47,774	$47,761	$2,755	$484,949
1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	8,980	53,537	10,074	4,346	113,464	102,651	64,437	2,788	2,796	2,774	2,761	2,755	371,361
2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	0	0	0	0	0	0	2,000	2,000	2,000	2,000	8,000
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	2,120	4,060	4,165	16,202	(16,942)	2,596	6,127	6,409	5,741	2,524	2,243	2,350	37,593
6	Phase II Cooling Water Intake 316(b) - Base	13,731	21,490	0	15,301	21,518	16,313	22,387	44,059	0	38,700	0	38,700	232,200
6a	Phase II Cooling Water Intake 316(b) - Intm	3,372	(2,497)	19,663	(10,798)	11,523	5,425	0	2,100	0	2,100	0	2,100	32,989
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	1,041,316	1,584,385	2,500,543	1,171,970	1,356,473	703,618	1,229,840	1,129,229	1,129,229	1,504,229	1,329,229	1,347,229	16,027,287
7.4	CAIR/CAMR Crystal River - Energy	1,545,081	1,406,596	973,788	808,867	1,125,740	1,342,445	1,658,500	1,778,059	1,730,721	1,741,659	1,665,652	1,684,340	17,461,449
7.4	CAIR/CAMR Crystal River - A&G	6,615	7,910	10,909	7,146	7,059	8,927	7,245	8,086	8,086	8,086	8,086	8,086	96,243
7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	0	0	0	0	0	0	0	0	0	0	247,500	247,500	495,000
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	11,543	14,370	20,742	43,080	0	23,437	1,563	25,000	20,228	0	10,265	0	170,228
9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0	0	0	200	200	200	0	0	0	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	10,000	10,000	8,000	6,000	6,000	40,000
16	National Pollutant Discharge Elimination System (NPDES) - Energy	0	0	11,423	544	2,263	0	7,000	0	0	0	4,410	6,680	32,320
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	0	0	472	13,715	24,714	1,406	98,594	50,000	65,000	65,000	70,000	70,000	458,901
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	117,224	119,295	151,138	187,439	116,787	127,083	117,917	120,000	110,000	110,000	110,000	110,000	1,496,883
18	Coal Combustion Residual (CCR) Rule - Energy	17,784	11,104	13,995	12,437	15,370	34,598	125,997	130,845	130,845	124,645	151,085	127,145	895,851
2	Total O&M Activities - Recoverable Costs	$2,783,684	$3,292,049	$3,760,501	$2,317,762	$2,823,460	$2,398,332	$3,396,742	$3,309,562	$3,287,642	$3,657,490	$3,656,991	$3,657,639	$38,341,855
3	Recoverable Costs Allocated to Energy	1,682,210	1,541,054	1,154,981	1,039,205	1,267,932	1,508,128	2,014,134	2,095,313	2,052,308	2,051,828	2,256,890	2,254,015	20,917,997
4	Recoverable Costs Allocated to Demand - Transm	15,917	71,800	43,589	47,512	45,491	29,833	56,935	2,788	72,796	47,774	47,761	2,755	484,949
	Recoverable Costs Allocated to Demand - Distrib	8,980	53,537	10,074	4,346	113,464	102,651	64,637	2,988	4,996	4,774	4,761	4,755	379,961
	Recoverable Costs Allocated to Demand - Prod-Base	1,066,590	1,620,245	2,521,285	1,230,351	1,377,992	743,368	1,253,790	1,198,288	1,149,457	1,542,929	1,339,494	1,385,929	16,429,715
	Recoverable Costs Allocated to Demand - Prod-Intm	3,372	(2,497)	19,663	(10,798)	11,523	5,425	0	2,100	0	2,100	0	2,100	32,989
	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	6,615	7,910	10,909	7,146	7,059	8,927	7,245	8,086	8,086	8,086	8,086	8,086	96,243
5	Retail Energy Jurisdictional Factor	0.95280	0.95010	0.94890	0.95290	0.93750	0.93350	0.95843	0.95971	0.96310	0.96469	0.97067	0.96209	
	Retail Energy Jurisdictional Factor - NOx Regulatory Asset	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
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)	1,602,809	1,464,156	1,095,961	990,258	1,188,686	1,407,838	1,930,397	2,010,894	1,976,571	1,979,379	2,190,697	2,168,568	20,006,214
8	Jurisdictional Demand Recoverable Costs - Transm (B)	11,174	50,406	30,601	33,355	31,936	20,944	39,970	1,957	51,105	33,539	33,529	1,934	340,450
	Jurisdictional Demand Recoverable Costs - Distrib (B)	8,941	53,302	10,030	4,327	112,966	102,200	64,354	2,975	4,974	4,753	4,740	4,734	378,296
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	990,702	1,504,964	2,341,896	1,142,812	1,279,948	690,477	1,164,582	1,113,029	1,067,673	1,433,149	1,244,189	1,287,320	15,260,741
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	2,452	(1,815)	14,296	(7,850)	8,378	3,944	0	1,527	0	1,527	0	1,527	23,986
	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)	6,167	7,374	10,169	6,662	6,580	8,322	6,754	7,538	7,538	7,538	7,538	7,538	89,718
9	Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8)	$2,622,245	$3,078,387	$3,502,953	$2,169,564	$2,628,494	$2,233,725	$3,206,057	$3,137,920	$3,107,861	$3,459,885	$3,480,693	$3,471,621	$36,099,405

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 2018 - December 2018

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	$658,083	$667,875	($9,792)	-1%
	4.x	Above Ground Tank Secondary Containment	1,774,030	1,901,269	(127,239)	-7%
	5	SO2/NOx Emissions Allowances	269,466	316,458	(46,992)	-15%
	6	Phase II Cooling Water Intake 316(b) - Base	86,505	265,853	(179,348)	-67%
	7.x	CAIR/CAMR	5,191,433	6,129,657	(938,224)	-15%
	9	Sea Turtle - Coastal Street Lighting	1,123	1,222	(99)	-8%
	10.x	Underground Storage Tanks	22,459	24,897	(2,438)	-10%
	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)	36,219	23,472	12,747	54%
	16	National Pollutant Discharge Elimination System (NPDES)	1,491,493	1,651,435	(159,942)	-10%
	17x	Mercury & Air Toxics Standards (MATS)	16,624,582	18,651,750	(2,027,168)	-11%
	18	Coal Combustion Residual (CCR) Rule	36,576	47,623	(11,047)	-23%
2		Total Capital Investment Activities - Recoverable Costs	$26,191,969	$29,681,511	($3,489,542)	-12%
3		Recoverable Costs Allocated to Energy	$16,990,268	$19,090,929	($2,100,661)	-11%
4		Recoverable Costs Allocated to Demand	$9,201,701	$10,590,582	($1,388,881)	-13%

Notes:

Column (1) End of Period Totals on Form 42-7E
Column (2) 2017 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 2018 - December 2018

Capital Investment Projects-Recoverable Costs
(in Dollars)

Form 42-7E

Docket No. 20180007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)

Line	Description	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investment Projects - System (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intermediate	$56,772	$56,423	$56,079	$55,730	$55,386	$55,039	54,629	$54,288	$53,948	$53,604	$53,263	$52,920	$658,083
4.1	Above Ground Tank Secondary Containment - Peaking	128,806	128,298	127,783	127,276	126,763	126,251	125,148	124,643	124,139	123,635	123,131	122,628	1,508,501
4.2	Above Ground Tank Secondary Containment - Base	20,150	20,130	20,108	20,087	20,067	20,046	19,800	19,779	19,758	19,739	19,717	19,696	239,077
4.3	Above Ground Tank Secondary Containment - Intermediate	2,234	2,230	2,227	2,224	2,220	2,216	2,192	2,189	2,185	2,181	2,179	2,175	26,452
5	SO2/NOX Emissions Allowances - Energy	22,817	22,795	22,767	22,696	22,630	22,612	22,277	22,234	22,192	22,165	22,148	22,133	269,466
6	Phase II Cooling Water Intake 316(b) - Base	4,876	5,168	5,845	7,476	8,274	6,608	6,586	8,170	8,237	8,305	8,372	8,588	86,505
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	17,980	17,934	17,887	17,841	17,797	17,751	17,573	17,530	17,484	17,438	17,393	17,352	211,958
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	254,639	276,837	310,523	343,882	364,137	388,045	414,984	452,166	488,086	515,807	532,029	542,120	4,883,255
7.4	CAIR/CAMR Crystal River AFUDC - Energy	8,239	8,552	8,191	7,524	7,798	8,106	7,848	7,971	7,977	7,968	8,010	8,036	96,220
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	93	93	92	92	92	92	92	94	95	96	96	96	1,123
10.1	Underground Storage Tanks - Base	1,291	1,290	1,287	1,286	1,283	1,282	1,268	1,266	1,264	1,262	1,260	1,258	15,297
10.2	Underground Storage Tanks - Intermediate	607	605	604	603	601	600	594	592	591	590	588	587	7,162
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	1,570	1,572	1,574	1,576	1,585	1,586	1,558	2,336	3,890	5,288	6,376	7,308	36,219
16	National Pollutant Discharge Elimination System (NPDES) - Intermediate	126,174	125,927	125,680	125,433	125,186	124,938	123,635	123,391	123,148	122,904	122,661	122,416	1,491,493
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	30,736	30,690	30,645	30,599	30,554	30,508	30,140	30,095	30,050	30,005	29,959	29,915	363,900
17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	1,178,275	1,166,527	1,164,848	1,163,170	1,161,492	1,159,814	1,146,871	1,145,215	1,143,559	1,141,903	1,140,247	1,138,591	13,850,506
17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	204,413	203,925	203,440	202,957	202,473	201,988	199,690	199,212	198,735	198,257	197,779	197,302	2,410,176
18	Coal Combustion Residual (CCR) Rule - Base	2,800	2,798	2,797	2,796	2,794	2,793	2,808	3,027	3,365	3,534	3,532	3,532	36,576
2	Total Investment Projects - Recoverable Costs	$2,062,472	$2,071,794	$2,102,377	$2,133,248	$2,151,132	$2,170,275	$2,177,693	$2,214,198	$2,248,703	$2,274,681	$2,288,741	$2,296,653	$26,191,969
3	Recoverable Costs Allocated to Energy	1,444,480	1,432,489	1,429,891	1,426,946	1,424,947	1,423,029	1,406,826	1,404,727	1,402,513	1,400,298	1,398,144	1,395,977	16,990,268
	Recoverable Costs Allocated to Distribution Demand	93	93	92	92	92	92	92	94	95	96	96	96	1,123
4	Recoverable Costs Allocated to Demand - Production - Base	285,326	307,795	342,134	377,103	398,140	420,360	447,004	486,744	524,600	553,935	571,286	582,502	5,296,929
	Recoverable Costs Allocated to Demand - Production - Intermediate	185,787	185,185	184,590	183,990	183,393	182,793	181,050	180,460	179,872	179,279	178,691	178,098	2,183,190
	Recoverable Costs Allocated to Demand - Production - Peaking	146,786	146,232	145,670	145,117	144,560	144,002	142,721	142,173	141,623	141,073	140,524	139,980	1,720,459
5	Retail Energy Jurisdictional Factor	0.95280	0.95010	0.94890	0.95290	0.93750	0.93350	0.95843	0.95971	0.96310	0.96469	0.97067	0.96209	
	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	
	Retail Demand Jurisdictional Factor - Production - Base (2012)	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	0.91683	
7	Jurisdictional Energy Recoverable Costs (B)	1,376,301	1,361,008	1,356,824	1,359,737	1,335,888	1,328,397	1,348,338	1,348,132	1,350,756	1,350,854	1,357,137	1,343,057	16,216,429
	Jurisdictional Demand Recoverable Costs - Distribution (B)	93	93	92	92	92	92	92	94	95	96	96	96	1,118
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	265,025	285,895	317,791	350,272	369,812	390,451	415,200	452,112	487,275	514,523	530,639	541,057	4,920,053
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	135,073	134,635	134,203	133,766	133,332	132,896	131,629	131,200	130,772	130,341	129,914	129,483	1,587,245
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	140,803	140,271	139,732	139,202	138,668	138,132	136,903	136,378	135,850	135,323	134,796	134,274	1,650,333
9	Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8)	$1,917,294	$1,921,902	$1,948,641	$1,983,069	$1,977,792	$1,989,968	$2,032,161	$2,067,916	$2,104,748	$2,131,136	$2,152,582	$2,147,967	$24,375,177

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 2018 - December 2018

Docket No. 20180007-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: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline - Intermediate (Project 3.1)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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)			1,000,345	950,328	900,311	850,294	800,277	750,260	700,243	650,226	600,209	550,192	500,175	450,158	400,142	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,000,345	$950,328	$900,311	$850,294	$800,277	$750,260	$700,243	$650,226	$600,209	$550,193	$500,176	$450,159	$400,142	
6	Average Net Investment				$975,336	$925,319	$875,302	$825,286	$775,269	$725,252	$675,235	$625,218	$575,201	$525,184	$475,167	$425,150	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		1,641	1,555	1,472	1,387	1,304	1,220	1,107	1,025	944	861	779	697	13,992
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		5,114	4,851	4,590	4,326	4,065	3,802	3,505	3,246	2,987	2,726	2,467	2,206	43,885
	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	50,017	50,017	50,017	50,017	50,017	600,206
	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)				$56,772	$56,423	$56,079	$55,730	$55,386	$55,039	$54,629	$54,288	$53,948	$53,604	$53,263	$52,920	658,083
	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				56,772	56,423	56,079	55,730	55,386	55,039	54,629	54,288	53,948	53,604	53,263	52,920	658,083
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)				41,275	41,021	40,771	40,518	40,267	40,015	39,717	39,469	39,222	38,972	38,724	38,475	478,446
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$41,275	$41,021	$40,771	$40,518	$40,267	$40,015	$39,717	$39,469	$39,222	$38,972	$38,724	$38,475	$478,446

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 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 Pipeline Integrity Management 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 2017 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 amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI. Project 3.1a amortized over 26 months as approved in Order PSC-2018-0014-FOF-EI.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2018 - December 2018

Docket No. 20180007-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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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)			$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	$9,235,204	
3	Less: Accumulated Depreciation			(3,073,848)	(3,101,917)	(3,129,986)	(3,158,055)	(3,186,124)	(3,214,193)	(3,242,262)	(3,270,331)	(3,298,400)	(3,326,469)	(3,354,538)	(3,382,607)	(3,410,676)	
3a	Regulatory Asset Balance (G)			685,616	639,909	594,202	548,495	502,788	457,081	411,374	365,667	319,960	274,253	228,546	182,839	137,132	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$6,846,972	$6,773,196	$6,699,420	$6,625,644	$6,551,868	$6,478,092	$6,404,316	$6,330,540	$6,256,764	$6,182,988	$6,109,212	$6,035,436	$5,961,660	
6	Average Net Investment				$6,810,084	$6,736,308	$6,662,532	$6,588,756	$6,514,980	$6,441,204	$6,367,428	$6,293,652	$6,219,876	$6,146,100	$6,072,324	$5,998,548	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		11,449	11,328	11,202	11,079	10,954	10,829	10,441	10,320	10,200	10,078	9,957	9,836	127,673
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		35,705	35,318	34,929	34,545	34,157	33,770	33,055	32,671	32,287	31,905	31,522	31,140	401,004
	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	336,828
	b. Amortization (G)				45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	548,484
	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)				7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	7,876	94,512
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$128,806	$128,298	$127,783	$127,276	$126,763	$126,251	$125,148	$124,643	$124,139	$123,635	$123,131	$122,628	1,508,501
	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				128,806	128,298	127,783	127,276	126,763	126,251	125,148	124,643	124,139	123,635	123,131	122,628	1,508,501
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)				123,556	123,069	122,575	122,088	121,596	121,105	120,047	119,563	119,079	118,596	118,112	117,630	1,447,014
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$123,556	$123,069	$122,575	$122,088	$121,596	$121,105	$120,047	$119,563	$119,079	$118,596	$118,112	$117,630	$1,447,014

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.

(E) Line 9a x Line 10

(F) Line 9b x Line 11

(G) Project 4.1a 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
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Docket No. 20180007-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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			$27,233	24,201	21,169	18,137	15,105	12,073	9,041	6,009	2,977	(55)	(3,087)	(6,119)	(9,151)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,426,272	$2,423,240	$2,420,208	$2,417,176	$2,414,144	$2,411,112	$2,408,080	$2,405,048	$2,402,016	$2,398,984	$2,395,952	$2,392,920	$2,389,888	
6	Average Net Investment				$2,424,756	$2,421,724	$2,418,692	$2,415,660	$2,412,628	$2,409,596	$2,406,564	$2,403,532	$2,400,500	$2,397,468	$2,394,436	$2,391,404	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		4,077	4,072	4,066	4,062	4,057	4,052	3,946	3,941	3,936	3,932	3,926	3,921	47,988
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		12,712	12,697	12,681	12,664	12,649	12,633	12,493	12,477	12,461	12,446	12,430	12,414	150,757
	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)				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
9	Total System Recoverable Expenses (Lines 7 + 8)				$20,150	$20,130	$20,108	$20,087	$20,067	$20,046	$19,800	$19,779	$19,758	$19,739	$19,717	$19,696	239,077
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				20,150	20,130	20,108	20,087	20,067	20,046	19,800	19,779	19,758	19,739	19,717	19,696	239,077
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)				18,716	18,698	18,677	18,658	18,639	18,620	18,391	18,372	18,352	18,335	18,314	18,295	222,067
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$18,716	$18,698	$18,677	$18,658	$18,639	$18,620	$18,391	$18,372	$18,352	$18,335	$18,314	$18,295	$222,067

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Docket No. 20180007-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 - Intermediate (Project 4.3)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(72,786)	(73,311)	(73,836)	(74,361)	(74,886)	(75,411)	(75,936)	(76,461)	(76,986)	(77,511)	(78,036)	(78,561)	(79,086)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)			$217,512	$216,987	$216,462	$215,937	$215,412	$214,887	$214,362	$213,837	$213,312	$212,787	$212,262	$211,737	$211,212	
6	Average Net Investment				$217,249	$216,724	$216,199	$215,674	$215,149	$214,624	$214,099	$213,574	$213,049	$212,524	$211,999	$211,474	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		365	364	364	363	362	361	351	350	349	348	348	347	4,272
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		1,139	1,136	1,133	1,131	1,128	1,125	1,111	1,109	1,106	1,103	1,101	1,098	13,420
	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)				$2,234	$2,230	$2,227	$2,224	$2,220	$2,216	$2,192	$2,189	$2,185	$2,181	$2,179	$2,175	26,452
	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				2,234	2,230	2,227	2,224	2,220	2,216	2,192	2,189	2,185	2,181	2,179	2,175	26,452
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 (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)				1,624	1,621	1,619	1,617	1,614	1,611	1,594	1,591	1,589	1,586	1,584	1,581	19,231
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,624	$1,621	$1,619	$1,617	$1,614	$1,611	$1,594	$1,591	$1,589	$1,586	$1,584	$1,581	$19,231

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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
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SO2 and NOx EMISSIONS ALLOWANCES - Energy (Project 5)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0158150 SO_2 Emission Allowance Inventory			$3,296,898	$3,294,754	$3,290,670	$3,286,482	$3,270,255	$3,267,330	$3,264,702	$3,258,542	$3,252,100	$3,246,326	$3,243,770	$3,241,494	$3,239,111	$3,239,111
	b. 0254020 Auctioned SO_2 Allowance			(610)	(586)	(562)	(538)	(514)	(447)	(414)	(381)	(348)	(315)	(282)	(249)	(216)	(216)
	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			$3,296,289	$3,294,168	$3,290,108	$3,285,944	$3,269,741	$3,266,884	$3,264,288	$3,258,161	$3,251,752	$3,246,011	$3,243,488	$3,241,245	$3,238,895	$3,238,895
3	Average Net Investment				$3,295,228	$3,292,138	$3,288,026	$3,277,842	$3,268,313	$3,265,586	$3,261,225	$3,254,957	$3,248,882	$3,244,749	$3,242,366	$3,240,070	
4	Return on Average Net Working Capital Balance (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		5,541	5,535	5,529	5,511	5,495	5,491	5,348	5,337	5,327	5,321	5,317	5,313	65,065
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		17,276	17,260	17,238	17,185	17,135	17,121	16,929	16,897	16,865	16,844	16,831	16,820	204,401
5	Total Return Component (C)				$22,817	$22,795	$22,767	$22,696	$22,630	$22,612	$22,277	$22,234	$22,192	$22,165	$22,148	$22,133	269,466
6	Expense Dr (Cr)																
	a. 0509030 SO_2 Allowance Expense				$2,144	$4,084	$4,189	$16,226	$2,925	$2,629	$6,159	$6,442	$5,774	$2,556	$2,276	$2,383	57,787
	b. 0407426 Amortization Expense				(24)	(24)	(24)	(24)	(67)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(394)
	c. 0509212 NOx Allowance Expense				0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other (G)				0	0	0	0	(19,800)	0	0	0	0	0	0	0	(19,800)
7	Net Expense (D)				2,120	4,060	4,165	16,202	(16,942)	2,596	6,127	6,409	5,741	2,524	2,243	2,350	37,593
8	Total System Recoverable Expenses (Lines 5 + 7)				$24,937	$26,855	$26,932	$38,898	$5,688	$25,208	$28,404	$28,643	$27,933	$24,689	$24,391	$24,483	307,059
	a. Recoverable Costs Allocated to Energy				24,937	26,855	26,932	38,898	5,688	25,208	28,404	28,643	27,933	24,689	24,391	24,483	307,059
	b. Recoverable Costs Allocated to Demand				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor				0.95280	0.95010	0.94890	0.95290	0.93750	0.93350	0.95843	0.95971	0.96310	0.96469	0.97067	0.96209	
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)				$23,760	$25,515	$25,556	$37,066	$5,332	$23,532	$27,223	$27,489	$26,903	$23,817	$23,676	$23,555	293,421
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)				$ 23,760	$ 25,515	$ 25,556	$ 37,066	$ 5,332	$ 23,532	$ 27,223	$ 27,489	$ 26,903	$ 23,817	$ 23,676	$ 23,555	$ 293,421

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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

(G) There was a Seasonal NOX credit in May 2018 of $19,800. This was the result of sales of allowances that were allocated to DEF by the EPA at zero cost.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
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Docket No. 20180007-EI
Duke Energy Florida
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	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments														
	a. Expenditures/Additions		$81,980	$2,210	$193,266	$277,856	($47,238)	($434,111)	$453,936	$9,825	$9,825	$9,825	$9,825	$53,476	$620,675
	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	$663,307	745,287	747,497	940,763	1,218,619	1,171,381	737,270	1,191,206	1,201,031	1,210,856	1,220,681	1,230,506	1,283,982	
5	Net Investment (Lines 2 + 3 + 4)	$663,307	$745,287	$747,497	$940,763	$1,218,619	$1,171,381	$737,270	$1,191,206	$1,201,031	$1,210,856	$1,220,681	$1,230,506	$1,283,982	
6	Average Net Investment		$704,297	$746,392	$844,130	$1,079,691	$1,195,000	$954,326	$964,238	$1,196,119	$1,205,944	$1,215,769	$1,225,594	$1,257,244	
7	Return on Average Net Investment (B)	Jan-Jun Jul-Dec													
	a. Debt Component	2.02% 1.97%	1,184	1,255	1,419	1,815	2,009	1,605	1,581	1,961	1,977	1,994	2,010	2,062	20,872
	b. Equity Component Grossed Up For Taxes	6.29% 6.23%	3,692	3,913	4,426	5,661	6,265	5,003	5,005	6,209	6,260	6,311	6,362	6,526	65,633
	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)		$4,876	$5,168	$5,845	$7,476	$8,274	$6,608	$6,586	$8,170	$8,237	$8,305	$8,372	$8,588	86,505
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$4,876	$5,168	$5,845	$7,476	$8,274	$6,608	$6,586	$8,170	$8,237	$8,305	$8,372	$8,588	86,505
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)		4,529	4,800	5,429	6,944	7,685	6,138	6,117	7,589	7,651	7,714	7,776	7,977	80,350
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,529	$4,800	$5,429	$6,944	$7,685	$6,138	$6,117	$7,589	$7,651	$7,714	$7,776	$7,977	$80,350

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Docket No. 20180007-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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$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	$1,802,096	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	1,802,096	
3	Less: Accumulated Depreciation	(410,841)	(414,255)	(417,669)	(421,083)	(424,497)	(427,911)	(431,325)	(434,739)	(438,153)	(441,567)	(444,981)	(448,395)	(451,809)	
3a	Regulatory Asset Balance (G)	48,372	45,147	41,922	38,698	35,473	32,248	29,023	25,798	22,574	19,349	16,124	12,899	9,674	
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)	$1,439,627	$1,432,989	$1,426,350	$1,419,711	$1,413,072	$1,406,433	$1,399,795	$1,393,156	$1,386,517	$1,379,878	$1,373,239	$1,366,601	$1,359,962	
6	Average Net Investment		$1,436,308	$1,429,669	$1,423,030	$1,416,392	$1,409,753	$1,403,114	$1,396,475	$1,389,836	$1,383,198	$1,376,559	$1,369,920	$1,363,281	
7	Return on Average Net Investment (B)	Jan-Jun / Jul-Dec													
	a. Debt Component	2.02% / 1.97%	2,415	2,404	2,392	2,381	2,371	2,359	2,289	2,279	2,268	2,257	2,246	2,238	27,899
	b. Equity Component Grossed Up For Taxes	6.29% / 6.23%	7,530	7,495	7,460	7,425	7,391	7,357	7,249	7,216	7,181	7,146	7,112	7,079	87,641
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C)		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	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	38,698
	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)		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)		$17,980	$17,934	$17,887	$17,841	$17,797	$17,751	$17,573	$17,530	$17,484	$17,438	$17,393	$17,352	211,958
	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		17,980	17,934	17,887	17,841	17,797	17,751	17,573	17,530	17,484	17,438	17,393	17,352	211,958
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)		17,247	17,203	17,158	17,114	17,071	17,027	16,857	16,815	16,771	16,727	16,684	16,645	203,318
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,247	$17,203	$17,158	$17,114	$17,071	$17,027	$16,857	$16,815	$16,771	$16,727	$16,684	$16,645	$203,318

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.

(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 2018 - December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)
(in Dollars)

Docket No. 20180007-EI
Duke Energy Florida
Witness: C. A. Menendez
Exh. No. __ (CAM-3)
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Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$3,357,899	$3,068,868	$6,676,348	$2,974,452	$2,891,636	$4,028,331	$5,374,151	$5,527,579	$5,004,520	$3,127,296	$1,637,572	$1,331,905	$45,000,558
	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			$3,930,012	3,930,012	3,930,012	3,930,012	3,930,012	3,930,012	3,930,012	3,930,012	3,930,012	3,930,012	3,930,012	3,930,012	3,930,012	
3	Less: Accumulated Depreciation			($276,456)	(284,042)	(291,628)	(299,214)	(306,800)	(314,386)	(321,972)	(329,558)	(337,144)	(344,730)	(352,316)	(359,902)	(367,488)	
4	CWIP - Non-Interest Bearing			30,270,290	33,628,190	36,697,058	43,373,406	46,347,858	49,239,494	53,267,824	58,641,976	64,169,555	69,174,075	72,301,371	73,938,944	75,270,849	
5	Net Investment (Lines 2 + 3 + 4)			$33,923,847	$37,274,160	$40,335,443	$47,004,205	$49,971,070	$52,855,120	$56,875,865	$62,242,430	$67,762,423	$72,759,358	$75,879,068	$77,509,054	$78,833,373	
6	Average Net Investment				$35,599,004	$38,804,802	$43,669,824	$48,487,637	$51,413,095	$54,865,493	$59,559,148	$65,002,427	$70,260,891	$74,319,213	$76,694,061	$78,171,214	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		59,857	65,247	73,427	81,528	86,446	92,253	97,662	106,588	115,211	121,864	125,759	128,181	1,154,023
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		186,638	203,446	228,952	254,210	269,547	287,648	309,178	337,434	364,731	385,799	398,126	405,795	3,631,504
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)				7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	7,586	91,032
	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	558	558	558	558	558	558	558	558	558	558	558	6,696
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$254,639	$276,837	$310,523	$343,882	$364,137	$388,045	$414,984	$452,166	$488,086	$515,807	$532,029	$542,120	4,883,255
	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				254,639	276,837	310,523	343,882	364,137	388,045	414,984	452,166	488,086	515,807	532,029	542,120	4,883,255
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)				236,521	257,140	288,429	319,415	338,229	360,436	385,458	419,994	453,359	479,107	494,175	503,548	4,535,811
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$236,521	$257,140	$288,429	$319,415	$338,229	$360,436	$385,458	$419,994	$453,359	$479,107	$494,175	$503,548	$4,535,811

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Docket No. 20180007-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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Working Capital Dr (Cr)																
	a. 0154401 Ammonia Inventory			$9,781	$192,137	$134,599	$59,285	$35,567	$95,990	$21,951	$89,922	$89,922	$89,922	$89,922	$89,922	$89,922	$89,922
	b. 0154200 Limestone Inventory			$1,137,114	1,040,771	1,102,615	1,069,412	1,009,001	1,111,731	1,111,751	1,074,214	1,079,787	1,075,983	1,077,078	1,088,424	1,084,539	1,084,539
2	Total Working Capital			$1,146,895	$1,232,908	$1,237,214	$1,128,697	$1,044,568	$1,207,721	$1,133,703	$1,164,135	$1,169,709	$1,165,904	$1,166,999	$1,178,345	$1,174,461	1,174,461
3	Average Net Investment				1,189,902	1,235,061	1,182,956	1,086,632	1,126,144	1,170,712	1,148,919	1,166,922	1,167,807	1,166,452	1,172,672	1,176,403	
4	Return on Average Net Working Capital Balance (A)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		2,001	2,077	1,989	1,827	1,894	1,968	1,884	1,913	1,915	1,913	1,923	1,929	$23,232
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		6,238	6,475	6,202	5,697	5,904	6,138	5,964	6,058	6,062	6,055	6,087	6,107	72,988
5	Total Return Component (B)				8,239	8,552	8,191	7,524	7,798	8,106	7,848	7,971	7,977	7,968	8,010	8,036	96,220
6	Expense Dr (Cr)																
	a. 0502030 Ammonia Expense				300,866	345,474	382,972	236,235	263,893	258,209	441,791	480,000	480,000	480,000	480,000	480,000	4,629,441
	b. 0502040 Limestone Expense				650,788	517,063	341,025	306,664	422,624	555,987	728,619	735,837	680,662	681,346	628,443	658,926	6,907,984
	c. 0502050 Dibasic Acid Expense				0	26,526	0	0	0	0	0	0	0	0	0	0	26,526
	d. 0502070 Gypsum Disposal/Sale				214,439	208,716	90,248	102,248	185,879	201,449	251,891	254,221	235,059	235,314	217,209	227,414	2,424,086
	b. 0502040 Hydrated Lime Expense				368,739	285,489	182,781	179,375	253,344	326,801	228,199	300,000	325,000	325,000	320,000	300,000	3,394,728
	f. 0502300 Caustic Expense				10,248	23,329	(23,238)	(15,655)	0	0	8,000	8,000	10,000	20,000	20,000	18,000	78,684
7	Net Expense (C)				1,545,081	1,406,596	973,788	808,867	1,125,740	1,342,445	1,658,500	1,778,059	1,730,721	1,741,659	1,665,652	1,684,340	17,461,449
8	Total System Recoverable Expenses (Lines 5 + 7)			$1,553,320	$1,415,148	$981,979	$816,391	$1,133,537	$1,350,552	$1,666,348	$1,786,030	$1,738,698	$1,749,627	$1,673,663	$1,692,376	17,557,669	
	a. Recoverable Costs Allocated to Energy			1,553,320	1,415,148	981,979	816,391	1,133,537	1,350,552	1,666,348	1,786,030	1,738,698	1,749,627	1,673,663	1,692,376	17,557,669	
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0	
9	Energy Jurisdictional Factor			0.95280	0.95010	0.94890	0.95290	0.93750	0.93350	0.95843	0.95971	0.96310	0.96469	0.97067	0.96209		
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)			1,480,004	1,344,532	931,800	777,939	1,062,691	1,260,740	1,597,070	1,714,072	1,674,534	1,687,849	1,624,575	1,628,220	16,784,026	
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)			$ 1,480,004	$ 1,344,532	$ 931,800	$ 777,939	$ 1,062,691	$ 1,260,740	$ 1,597,070	$ 1,714,072	$ 1,674,534	$ 1,687,849	$ 1,624,575	$ 1,628,220	$ 16,784,026	

Notes:

(A) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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
January 2018 - December 2018

Docket No. 20180007-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: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$200	$200	$200	$0	$0	$0	$600
	b. Clearings to Plant				0	0	0	0	0	0	200	200	200	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	11,524	11,724	11,924	11,924	11,924	11,924	
3	Less: Accumulated Depreciation			(3,350)	(3,379)	(3,408)	(3,437)	(3,466)	(3,495)	(3,524)	(3,553)	(3,583)	(3,613)	(3,643)	(3,673)	(3,703)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$7,974	$7,945	$7,916	$7,887	$7,858	$7,829	$7,800	$7,971	$8,141	$8,311	$8,281	$8,251	$8,221	
6	Average Net Investment				$7,960	$7,931	$7,902	$7,873	$7,844	$7,815	$7,886	$8,056	$8,226	$8,296	$8,266	$8,236	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		13	13	13	13	13	13	13	13	13	14	14	14	159
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		42	42	41	41	41	41	41	42	43	43	43	43	503
	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	30	30	30	30	30	353
	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)	0.009414			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)				$93	$93	$92	$92	$92	$92	$92	$94	$95	$96	$96	$96	1,123
	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				$93	$93	$92	$92	$92	$92	$92	$94	$95	$96	$96	$96	1,123
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)				93	93	92	92	92	92	92	94	95	96	96	96	1,118
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$93	$93	$92	$92	$92	$92	$92	$94	$95	$96	$96	$96	$1,118

Notes:
(A) N/A
(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Docket No. 20180007-EI
Duke Energy Florida
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	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(42,448)	(42,744)	(43,040)	(43,336)	(43,632)	(43,928)	(44,224)	(44,520)	(44,816)	(45,112)	(45,408)	(45,704)	(46,000)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$126,493	$126,197	$125,901	$125,605	$125,309	$125,013	$124,717	$124,421	$124,125	$123,829	$123,533	$123,237	$122,941	
6	Average Net Investment				$126,345	$126,049	$125,753	$125,457	$125,161	$124,865	$124,569	$124,273	$123,977	$123,681	$123,385	$123,089	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		212	212	211	211	210	210	204	204	203	203	202	202	2,484
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		662	661	659	658	656	655	647	645	644	642	641	639	7,809
	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)				$1,291	$1,290	$1,287	$1,286	$1,283	$1,282	$1,268	$1,266	$1,264	$1,262	$1,260	$1,258	15,297
	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				$1,291	$1,290	$1,287	$1,286	$1,283	$1,282	$1,268	$1,266	$1,264	$1,262	$1,260	$1,258	15,297
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)				1,199	1,198	1,195	1,195	1,192	1,191	1,178	1,176	1,174	1,172	1,170	1,168	14,209
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,199	$1,198	$1,195	$1,195	$1,192	$1,191	$1,178	$1,176	$1,174	$1,172	$1,170	$1,168	$14,209

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Docket No. 20180007-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: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(26,657)	(26,860)	(27,063)	(27,266)	(27,469)	(27,672)	(27,875)	(28,078)	(28,281)	(28,484)	(28,687)	(28,890)	(29,093)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$49,349	$49,146	$48,943	$48,740	$48,537	$48,334	$48,131	$47,928	$47,725	$47,522	$47,319	$47,116	$46,913	
6	Average Net Investment				$49,248	$49,045	$48,842	$48,639	$48,436	$48,233	$48,030	$47,827	$47,624	$47,421	$47,218	$47,015	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		83	82	82	82	81	81	79	78	78	78	77	77	958
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		258	257	256	255	254	253	249	248	247	246	245	244	3,012
	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			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)				$607	$605	$604	$603	$601	$600	$594	$592	$591	$590	$588	$587	7,162
	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				$607	$605	$604	$603	$601	$600	$594	$592	$591	$590	$588	$587	7,162
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)				441	440	439	438	437	436	432	430	430	429	427	427	5,207
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$441	$440	$439	$438	$437	$436	$432	$430	$430	$429	$427	$427	$5,207

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Docket No. 20180007-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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$394	$386	$0	$2,633	($2,041)	$0	$227,500	$227,500	$182,000	$136,500	$136,500	$911,372
	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			226,768	226,768	227,162	227,548	227,548	230,181	228,140	228,140	455,640	683,140	865,140	1,001,640	1,138,140	
5	Net Investment (Lines 2 + 3 + 4)			$226,768	$226,768	$227,162	$227,548	$227,548	$230,181	$228,140	$228,140	$455,640	$683,140	$865,140	$1,001,640	$1,138,140	
6	Average Net Investment				$226,768	$226,965	$227,355	$227,548	$228,864	$229,160	$228,140	$341,890	$569,390	$774,140	$933,390	$1,069,890	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		381	382	382	383	385	385	374	561	934	1,269	1,531	1,754	8,721
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		1,189	1,190	1,192	1,193	1,200	1,201	1,184	1,775	2,956	4,019	4,845	5,554	27,498
	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)	0.001703			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)				$1,570	$1,572	$1,574	$1,576	$1,585	$1,586	$1,558	$2,336	$3,890	$5,288	$6,376	$7,308	36,219
	a. Recoverable Costs Allocated to Energy				1,570	1,572	1,574	1,576	1,585	1,586	1,558	2,336	3,890	5,288	6,376	7,308	36,219
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)				0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	
12	Retail Energy-Related Recoverable Costs (E)				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Retail Demand-Related Recoverable Costs (F)				$1,458	$1,460	$1,462	$1,464	$1,472	$1,473	$1,447	$2,170	$3,613	$4,912	$5,922	$6,788	33,641
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$1,458	$1,460	$1,462	$1,464	$1,472	$1,473	$1,447	$2,170	$3,613	$4,912	$5,922	$6,788	$33,641

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: NPDES - Intermediate (Project 16)
(in Dollars)

Docket No. 20180007-EI
Duke Energy Florida
Witness: C. A. Menendez
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Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(1,288,446)	(1,324,118)	(1,359,790)	(1,395,462)	(1,431,134)	(1,466,806)	(1,502,478)	(1,538,150)	(1,573,822)	(1,609,494)	(1,645,166)	(1,680,838)	(1,716,510)	
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)			$11,553,424	$11,517,752	$11,482,080	$11,446,408	$11,410,736	$11,375,064	$11,339,392	$11,303,720	$11,268,048	$11,232,376	$11,196,704	$11,161,032	$11,125,360	
6	Average Net Investment				$11,535,588	$11,499,916	$11,464,244	$11,428,572	$11,392,900	$11,357,228	$11,321,556	$11,285,884	$11,250,212	$11,214,540	$11,178,868	$11,143,196	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		19,396	19,336	19,276	19,216	19,156	19,096	18,565	18,506	18,448	18,389	18,331	18,272	225,987
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		60,479	60,292	60,105	59,918	59,731	59,543	58,771	58,586	58,401	58,216	58,031	57,845	709,918
	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)	0.009930			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)				$126,174	$125,927	$125,680	$125,433	$125,186	$124,938	$123,635	$123,391	$123,148	$122,904	$122,661	$122,416	1,491,493
	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				$126,174	$125,927	$125,680	$125,433	$125,186	$124,938	$123,635	$123,391	$123,148	$122,904	$122,661	$122,416	1,491,493
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)				91,732	91,553	91,373	91,194	91,014	90,834	89,886	89,709	89,532	89,355	89,178	89,000	1,084,360
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$91,732	$91,553	$91,373	$91,194	$91,014	$90,834	$89,886	$89,709	$89,532	$89,355	$89,178	$89,000	$1,084,360

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Docket No. 20180007-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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(187,997)	(194,579)	(201,161)	(207,743)	(214,325)	(220,907)	(227,489)	(234,071)	(240,653)	(247,235)	(253,817)	(260,399)	(266,981)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$3,502,190	$3,495,608	$3,489,026	$3,482,444	$3,475,862	$3,469,280	$3,462,698	$3,456,116	$3,449,534	$3,442,952	$3,436,370	$3,429,788	$3,423,206	
6	Average Net Investment				$3,498,899	$3,492,317	$3,485,735	$3,479,153	$3,472,571	$3,465,989	$3,459,407	$3,452,825	$3,446,243	$3,439,661	$3,433,079	$3,426,497	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		5,883	5,872	5,861	5,850	5,839	5,828	5,673	5,662	5,651	5,640	5,629	5,619	69,007
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		18,344	18,309	18,275	18,240	18,206	18,171	17,958	17,924	17,890	17,856	17,821	17,787	216,781
	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)	0.001703			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)				$30,736	$30,690	$30,645	$30,599	$30,554	$30,508	$30,140	$30,095	$30,050	$30,005	$29,959	$29,915	363,900
	a. Recoverable Costs Allocated to Energy				30,736	30,690	30,645	30,599	30,554	30,508	30,140	30,095	30,050	30,005	29,959	29,915	363,900
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.95280	0.95010	0.94890	0.95290	0.93750	0.93350	0.95843	0.95971	0.96310	0.96469	0.97067	0.96209	
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)				$29,286	$29,159	$29,079	$29,158	$28,645	$28,480	$28,887	$28,883	$28,941	$28,946	$29,081	$28,781	$347,326
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)				$29,286	$29,159	$29,079	$29,158	$28,645	$28,480	$28,887	$28,883	$28,941	$28,946	$29,081	$28,781	$347,326

Notes:
(A) N/A
(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Decrease in depreciation expense related to retired rate base assets as approved in Docket No. 19990007-EI, Order No. PSC-1999-2513-FOF-EI.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 20180007-EI
Duke Energy Florida
Witness: C. A. Menendez
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DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Calculation of Actual / Estimated Amount
January 2018 - December 2018

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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(11,639,662)	(11,882,076)	(12,124,490)	(12,366,904)	(12,609,318)	(12,851,732)	(13,094,146)	(13,336,560)	(13,578,974)	(13,821,388)	(14,063,802)	(14,306,216)	(14,548,630)	
4	CWIP - AFUDC Bearing			(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$122,278,605	$122,036,191	$121,793,777	$121,551,363	$121,308,949	$121,066,535	$120,824,121	$120,581,707	$120,339,293	$120,096,879	$119,854,465	$119,612,051	$119,369,637	
6	Average Net Investment				$122,157,398	$121,914,984	$121,672,570	$121,430,156	$121,187,742	$120,945,328	$120,702,914	$120,460,500	$120,218,086	$119,975,672	$119,733,258	$119,490,844	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		207,873	205,021	204,613	204,205	203,799	203,390	197,923	197,525	197,128	196,730	196,333	195,935	2,410,475
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		648,035	639,139	637,868	636,598	635,326	634,057	626,581	625,323	624,064	622,806	621,547	620,289	7,571,633
	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)	0.008490			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)				$1,178,275	$1,166,527	$1,164,848	$1,163,170	$1,161,492	$1,159,814	$1,146,871	$1,145,215	$1,143,559	$1,141,903	$1,140,247	$1,138,591	13,850,506
	a. Recoverable Costs Allocated to Energy				1,178,275	1,166,527	1,164,848	1,163,170	1,161,492	1,159,814	1,146,871	1,145,215	1,143,559	1,141,903	1,140,247	1,138,591	13,850,506
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.95280	0.95010	0.94890	0.95290	0.93750	0.93350	0.95843	0.95971	0.96310	0.96469	0.97067	0.96209	
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)				$1,122,660	$1,108,317	$1,105,324	$1,108,384	$1,088,898	$1,082,686	$1,099,190	$1,099,075	$1,101,357	$1,101,582	$1,106,804	$1,095,428	$13,219,705
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)				$1,122,660	$1,108,317	$1,105,324	$1,108,384	$1,088,898	$1,082,686	$1,099,190	$1,099,075	$1,101,357	$1,101,582	$1,106,804	$1,095,428	$13,219,705

Notes:
(A) N/A
(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			$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			(2,159,309)	(2,229,244)	(2,299,179)	(2,369,114)	(2,439,049)	(2,508,984)	(2,578,919)	(2,648,854)	(2,718,789)	(2,788,724)	(2,858,659)	(2,928,594)	(2,998,529)	
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)			$20,521,765	$20,451,830	$20,381,895	$20,311,960	$20,242,025	$20,172,090	$20,102,155	$20,032,220	$19,962,285	$19,892,350	$19,822,415	$19,752,480	$19,682,545	
6	Average Net Investment				$20,486,797	$20,416,862	$20,346,927	$20,276,992	$20,207,057	$20,137,122	$20,067,187	$19,997,252	$19,927,317	$19,857,382	$19,787,447	$19,717,512	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		34,439	34,320	34,203	34,087	33,967	33,850	32,905	32,790	32,676	32,561	32,446	32,332	400,576
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		107,360	106,991	106,623	106,256	105,892	105,524	104,171	103,808	103,445	103,082	102,719	102,356	1,258,227
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	3.7000%			69,935	69,935	69,935	69,935	69,935	69,935	69,935	69,935	69,935	69,935	69,935	69,935	839,220
	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 (D)	0.001703			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)				$204,413	$203,925	$203,440	$202,957	$202,473	$201,988	$199,690	$199,212	$198,735	$198,257	$197,779	$197,302	2,410,176
	a. Recoverable Costs Allocated to Energy				204,413	203,925	203,440	202,957	202,473	201,988	199,690	199,212	198,735	198,257	197,779	197,302	2,410,176
	b. Recoverable Costs Allocated to Demand				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor				0.95280	0.95010	0.94890	0.95290	0.93750	0.93350	0.95843	0.95971	0.96310	0.96469	0.97067	0.96209	
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)				$194,765	$193,750	$193,045	$193,398	$189,819	$188,556	$191,388	$191,186	$191,401	$191,257	$191,979	$189,823	$2,300,367
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)				$194,765	$193,750	$193,045	$193,398	$189,819	$188,556	$191,388	$191,186	$191,401	$191,257	$191,979	$189,823	$2,300,367

Notes:

(A) N/A

(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Docket No. 20180007-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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$0	$15,000	$49,663	$49,663	$0	$0	$0	$114,326
	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			$97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	
3	Less: Accumulated Depreciation			(2,112)	(2,288)	(2,464)	(2,640)	(2,816)	(2,992)	(3,168)	(3,344)	(3,520)	(3,696)	(3,872)	(4,048)	(4,224)	
4	CWIP - Non-Interest Bearing			281,429	281,429	281,429	281,429	281,429	281,429	281,429	296,429	346,092	395,755	395,755	395,755	395,755	
5	Net Investment (Lines 2 + 3 + 4)			$376,902	$376,726	$376,550	$376,374	$376,198	$376,022	$375,846	$390,670	$440,157	$489,644	$489,468	$489,292	$489,116	
6	Average Net Investment				$376,814	$376,638	$376,462	$376,286	$376,110	$375,934	$383,258	$415,413	$464,900	$489,556	$489,380	$489,204	
7	Return on Average Net Investment (B)	Jan-Jun	Jul-Dec														
	a. Debt Component	2.02%	1.97%		634	633	633	633	632	632	628	681	762	803	802	802	8,275
	b. Equity Component Grossed Up For Taxes	6.29%	6.23%		1,976	1,975	1,974	1,973	1,972	1,971	1,990	2,156	2,413	2,541	2,540	2,540	26,021
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation (C)	2.1695%			176	176	176	176	176	176	176	176	176	176	176	176	2,112
	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			14	14	14	14	14	14	14	14	14	14	14	14	168
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$2,800	$2,798	$2,797	$2,796	$2,794	$2,793	$2,808	$3,027	$3,365	$3,534	$3,532	$3,532	36,576
	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				2,800	2,798	2,797	2,796	2,794	2,793	2,808	3,027	3,365	3,534	3,532	3,532	36,576
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)				2,601	2,599	2,598	2,597	2,595	2,594	2,608	2,812	3,126	3,283	3,281	3,281	33,975
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)				$2,601	$2,599	$2,598	$2,597	$2,595	$2,594	$2,608	$2,812	$3,126	$3,283	$3,281	$3,281	$33,975

Notes:
(A) N/A
(B) Jan - Jun 2018 Line 6 x 8.31% x 1/12. Jul - Dec 2018 Line 6 x 8.20% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.70% (Jan-Jun) and 4.65% (Jul-Dec), and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 2018 - December 2018

Capital Structure and Cost Rates

Class of Capital	Retail Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$4,711,485,475	44.73%	0.10500	4.70%	6.29%
PS	-	0.00%	0.00000	0.00%	0.00%
LTD	3,931,532,102	37.33%	0.05290	1.97%	1.97%
STD	102,874,989	0.98%	0.00210	0.00%	0.00%
CD-Active	191,024,808	1.81%	0.02260	0.04%	0.04%
CD-Inactive	1,455,315	0.01%	0.00000	0.00%	0.00%
ADIT	1,772,932,910	16.83%	0.00000	0.00%	0.00%
FAS 109	(180,390,549)	-1.71%	0.00000	0.00%	0.00%
ITC	1,967,889	0.02%	0.00000	0.00%	0.00%
Total	$10,532,882,939	100.00%		6.71%	8.31%
			Total Debt	2.02%	2.02%
			Total Equity	4.70%	6.29% (A)

May 2017 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PAA-EU, Docket 120007-EI.

(A) The May 2017 Pre-Tax Weighted Cost Rate for Common Equity above reflects the impact of the reduction in the federal corporate income tax rate as a result of the 2018 Tax Cuts and Jobs Act.

Class of Capital	Retail Amount	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$ 5,022,459,234	44.29%	0.10500	4.65%	6.23%
PS	-	0.00%	0.00000	0.00%	0.00%
LTD	4,497,051,945	39.66%	0.04896	1.94%	1.94%
STD	(193,058,184)	-1.70%	0.00878	-0.01%	-0.01%
CD-Active	179,648,841	1.58%	0.02352	0.04%	0.04%
CD-Inactive	1,597,098	0.01%	0.00000	0.00%	0.00%
ADIT	1,826,908,909	16.11%	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	$ 11,339,847,250	100.00%		6.62%	8.20%
			Total Debt	1.97%	1.97%
			Total Equity	4.65%	6.23%

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 May 2018 DEF Surveillance Report reflects the tax reform adjustments as set forth in Paragraph 16 of DEF's 2017 Settlement.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause
Capital Program Detail

January 2018 - December 2018
Actuals for the Period January 2018 - June 2018
Estimates for the Period July 2018 - December 2018
Docket No. 20180007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 18
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF)(DIRECT)
DESCRIPTION: Christopher Menendez

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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)				18,203	17,293	16,383	15,473	14,563	13,654	12,744	11,834	10,924	10,014	9,104	8,195	7,285	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$18,203	$17,293	$16,383	$15,473	$14,564	$13,654	$12,744	$11,834	$10,924	$10,014	$9,105	$8,195	$7,285	
6	Average Net Investment					17,748	16,838	15,928	15,018	14,109	13,199	12,289	11,379	10,469	9,560	8,650	7,740	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		30	28	27	25	24	22	20	19	17	16	14	13	255
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		93	88	84	79	74	69	64	59	54	50	45	40	799
	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	910	910	910	910	910	10,921
	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	0.9772%				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$1,033	$1,026	$1,021	$1,014	$1,008	$1,001	$994	$988	$981	$976	$969	$963	$11,975
	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					$1,033	$1,026	$1,021	$1,014	$1,008	$1,001	$994	$988	$981	$976	$969	$963	$11,975

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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)				521,464	495,391	469,318	443,244	417,171	391,098	365,025	338,952	312,878	286,805	260,732	234,659	208,586	
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)				$521,464	$495,391	$469,318	$443,244	$417,171	$391,098	$365,025	$338,952	$312,878	$286,805	$260,732	$234,659	$208,586	
6	Average Net Investment					508,427	482,354	456,281	430,208	404,135	378,061	351,988	325,915	299,842	273,769	247,695	221,622	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		855	811	767	723	680	636	577	534	492	449	406	363	7,293
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		2,666	2,529	2,392	2,255	2,119	1,982	1,827	1,692	1,557	1,421	1,286	1,150	22,876
	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	26,073	26,073	26,073	26,073	312,878
	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	0.9772%				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$29,594	$29,413	$29,232	$29,051	$28,872	$28,691	$28,477	$28,299	$28,122	$27,943	$27,765	$27,586	$343,047
	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					$29,594	$29,413	$29,232	$29,051	$28,872	$28,691	$28,477	$28,299	$28,122	$27,943	$27,765	$27,586	$343,047

(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
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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)				$397,503	377,628	357,753	337,878	318,003	298,128	278,252	258,377	238,502	218,627	198,752	178,877	159,001	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$397,503	$377,628	$357,753	$337,878	$318,003	$298,128	$278,252	$258,377	$238,502	$218,627	$198,752	$178,877	$159,001	
6	Average Net Investment					387,566	367,691	347,816	327,940	308,065	288,190	268,315	248,440	228,565	208,689	188,814	168,939	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		652	618	585	551	518	485	440	407	375	342	310	277	5,560
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		2,032	1,928	1,824	1,719	1,615	1,511	1,393	1,290	1,187	1,083	980	877	17,439
	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	19,875	19,875	19,875	19,875	238,502
	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	0.9772%				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$22,559	$22,421	$22,284	$22,145	$22,008	$21,871	$21,708	$21,572	$21,437	$21,300	$21,165	$21,029	$261,501
	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					$22,559	$22,421	$22,284	$22,145	$22,008	$21,871	$21,708	$21,572	$21,437	$21,300	$21,165	$21,029	$261,501

For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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)				63,175	60,016	56,857	53,698	50,540	47,381	44,222	41,063	37,905	34,746	31,587	28,429	25,270	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$63,175	$60,016	$56,857	$53,698	$50,540	$47,381	$44,222	$41,063	$37,905	$34,746	$31,587	$28,429	$25,270	
6	Average Net Investment					61,595	58,436	55,278	52,119	48,960	45,802	42,643	39,484	36,325	33,167	30,008	26,849	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		104	98	93	88	82	77	70	65	60	54	49	44	884
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		323	306	290	273	257	240	221	205	189	172	156	139	2,771
	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	3,159	3,159	3,159	3,159	37,905
	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	0.9772%				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$3,586	$3,563	$3,542	$3,520	$3,498	$3,476	$3,450	$3,429	$3,408	$3,385	$3,364	$3,342	$41,560
	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					$3,586	$3,563	$3,542	$3,520	$3,498	$3,476	$3,450	$3,429	$3,408	$3,385	$3,364	$3,342	$41,560

(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
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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)				685,616	639,909	594,202	548,495	502,788	457,081	411,374	365,667	319,960	274,253	228,546	182,839	137,132	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$685,616	$639,909	$594,202	$548,495	$502,788	$457,081	$411,374	$365,667	$319,960	$274,253	$228,546	$182,839	$137,132	
6	Average Net Investment					662,763	617,056	571,349	525,642	479,935	434,228	388,521	342,814	297,107	251,400	205,693	159,986	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		1,114	1,038	961	884	807	730	637	562	487	412	337	262	8,231
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		3,475	3,235	2,995	2,756	2,516	2,277	2,017	1,780	1,542	1,305	1,068	831	25,797
	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	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	45,707	548,484
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	1.1630%				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$50,296	$49,980	$49,663	$49,347	$49,030	$48,714	$48,361	$48,049	$47,736	$47,424	$47,112	$46,800	$582,512
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$50,296	$49,980	$49,663	$49,347	$49,030	$48,714	$48,361	$48,049	$47,736	$47,424	$47,112	$46,800	$582,512

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(380,955)	(384,640)	(388,325)	(392,010)	(395,695)	(399,380)	(403,065)	(406,750)	(410,435)	(414,120)	(417,805)	(421,490)	(425,175)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$1,092,846	$1,089,161	$1,085,476	$1,081,791	$1,078,106	$1,074,421	$1,070,736	$1,067,051	$1,063,366	$1,059,681	$1,055,996	$1,052,311	$1,048,626	
6	Average Net Investment					1,091,003	1,087,318	1,083,633	1,079,948	1,076,263	1,072,578	1,068,893	1,065,208	1,061,523	1,057,838	1,054,153	1,050,468	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		1,834	1,828	1,822	1,816	1,810	1,803	1,753	1,747	1,741	1,735	1,729	1,723	21,341
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		5,720	5,701	5,681	5,662	5,643	5,623	5,549	5,530	5,510	5,491	5,472	5,453	67,035
	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	0.9930%				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)					$12,459	$12,434	$12,408	$12,383	$12,358	$12,331	$12,207	$12,182	$12,156	$12,131	$12,106	$12,081	$147,236
	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					$12,459	$12,434	$12,408	$12,383	$12,358	$12,331	$12,207	$12,182	$12,156	$12,131	$12,106	$12,081	$147,236

(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
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(1,053,467)	(1,062,606)	(1,071,745)	(1,080,884)	(1,090,023)	(1,099,162)	(1,108,301)	(1,117,440)	(1,126,579)	(1,135,718)	(1,144,857)	(1,153,996)	(1,163,135)	
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)				$608,197	$599,058	$589,919	$580,780	$571,641	$562,502	$553,363	$544,224	$535,085	$525,946	$516,807	$507,668	$498,529	
6	Average Net Investment					603,628	594,489	585,350	576,211	567,072	557,933	548,794	539,655	530,516	521,377	512,238	503,099	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		1,015	1,000	984	969	953	938	900	885	870	855	840	825	11,034
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		3,165	3,117	3,069	3,021	2,973	2,925	2,849	2,801	2,754	2,707	2,659	2,612	34,652
	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	0.8500%				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)					$14,496	$14,433	$14,369	$14,306	$14,242	$14,179	$14,065	$14,002	$13,940	$13,878	$13,815	$13,753	$169,478
	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					$14,496	$14,433	$14,369	$14,306	$14,242	$14,179	$14,065	$14,002	$13,940	$13,878	$13,815	$13,753	$169,478

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(89,897)	(90,613)	(91,329)	(92,045)	(92,761)	(93,477)	(94,193)	(94,909)	(95,625)	(96,341)	(97,057)	(97,773)	(98,489)	
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)				$89,041	$88,325	$87,609	$86,893	$86,177	$85,461	$84,745	$84,029	$83,313	$82,597	$81,881	$81,165	$80,449	
6	Average Net Investment					88,683	87,967	87,251	86,535	85,819	85,103	84,387	83,671	82,955	82,239	81,523	80,807	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		149	148	147	146	144	143	138	137	136	135	134	133	1,690
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		465	461	457	454	450	446	438	434	431	427	423	419	5,305
	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	0.9420%				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)					$1,470	$1,465	$1,460	$1,456	$1,450	$1,445	$1,432	$1,427	$1,423	$1,418	$1,413	$1,408	$17,267
	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					$1,470	$1,465	$1,460	$1,456	$1,450	$1,445	$1,432	$1,427	$1,423	$1,418	$1,413	$1,408	$17,267

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(220,616)	(222,438)	(224,260)	(226,082)	(227,904)	(229,726)	(231,548)	(233,370)	(235,192)	(237,014)	(238,836)	(240,658)	(242,480)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$509,679	$507,857	$506,035	$504,213	$502,391	$500,569	$498,747	$496,925	$495,103	$493,281	$491,459	$489,637	$487,815	
6	Average Net Investment					508,768	506,946	505,124	503,302	501,480	499,658	497,836	496,014	494,192	492,370	490,548	488,726	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		855	852	849	846	843	840	816	813	810	807	804	801	9,936
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		2,667	2,658	2,648	2,639	2,629	2,620	2,584	2,575	2,565	2,556	2,546	2,537	31,224
	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	0.9930%				604	604	604	604	604	604	604	604	604	604	604	604	7,248
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$5,948	$5,936	$5,923	$5,911	$5,898	$5,886	$5,826	$5,814	$5,801	$5,789	$5,776	$5,764	$70,272
	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					$5,948	$5,936	$5,923	$5,911	$5,898	$5,886	$5,826	$5,814	$5,801	$5,789	$5,776	$5,764	$70,272

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(358,152)	(361,004)	(363,856)	(366,708)	(369,560)	(372,412)	(375,264)	(378,116)	(380,968)	(383,820)	(386,672)	(389,524)	(392,376)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$679,047	$676,195	$673,343	$670,491	$667,639	$664,787	$661,935	$659,083	$656,231	$653,379	$650,527	$647,675	$644,823	
6	Average Net Investment					677,621	674,769	671,917	669,065	666,213	663,361	660,509	657,657	654,805	651,953	649,101	646,249	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		1,139	1,135	1,130	1,125	1,120	1,115	1,083	1,078	1,074	1,069	1,064	1,060	13,192
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		3,553	3,538	3,523	3,508	3,493	3,478	3,429	3,414	3,399	3,384	3,370	3,355	41,444
	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	0.8670%				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)					$8,293	$8,274	$8,254	$8,234	$8,214	$8,194	$8,113	$8,093	$8,074	$8,054	$8,035	$8,016	$97,848
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$8,293	$8,274	$8,254	$8,234	$8,214	$8,194	$8,113	$8,093	$8,074	$8,054	$8,035	$8,016	$97,848

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(728,030)	(735,867)	(743,704)	(751,541)	(759,378)	(767,215)	(775,052)	(782,889)	(790,726)	(798,563)	(806,400)	(814,237)	(822,074)	
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)				$2,888,874	$2,881,037	$2,873,200	$2,865,363	$2,857,526	$2,849,689	$2,841,852	$2,834,015	$2,826,178	$2,818,341	$2,810,504	$2,802,667	$2,794,830	
6	Average Net Investment					2,884,955	2,877,118	2,869,281	2,861,444	2,853,607	2,845,770	2,837,933	2,830,096	2,822,259	2,814,422	2,806,585	2,798,748	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		4,851	4,838	4,824	4,811	4,798	4,785	4,654	4,641	4,628	4,615	4,602	4,589	56,636
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		15,125	15,084	15,043	15,002	14,961	14,920	14,732	14,691	14,651	14,610	14,569	14,529	177,917
	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	1.1630%				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)					$31,318	$31,264	$31,209	$31,155	$31,101	$31,047	$30,728	$30,674	$30,621	$30,567	$30,513	$30,460	$370,657
	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					$31,318	$31,264	$31,209	$31,155	$31,101	$31,047	$30,728	$30,674	$30,621	$30,567	$30,513	$30,460	$370,657

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(60,342)	(60,583)	(60,824)	(61,065)	(61,306)	(61,547)	(61,788)	(62,029)	(62,270)	(62,511)	(62,752)	(62,993)	(63,234)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$81,092	$80,851	$80,610	$80,369	$80,128	$79,887	$79,646	$79,405	$79,164	$78,923	$78,682	$78,441	$78,200	
6	Average Net Investment					80,972	80,731	80,490	80,249	80,008	79,767	79,526	79,285	79,044	78,803	78,562	78,321	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		136	136	135	135	135	134	130	130	130	129	129	128	1,587
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		425	423	422	421	419	418	413	412	410	409	408	407	4,987
	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	1.3030%				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)					$956	$954	$952	$951	$949	$947	$938	$937	$935	$933	$932	$930	$11,314
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$956	$954	$952	$951	$949	$947	$938	$937	$935	$933	$932	$930	$11,314

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				$394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	
3	Less: Accumulated Depreciation				(182,388)	(184,165)	(185,942)	(187,719)	(189,496)	(191,273)	(193,050)	(194,827)	(196,604)	(198,381)	(200,158)	(201,935)	(203,712)	
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)				$212,580	$210,803	$209,026	$207,249	$205,472	$203,695	$201,918	$200,141	$198,364	$196,587	$194,810	$193,033	$191,256	
6	Average Net Investment					211,691	209,914	208,137	206,360	204,583	202,806	201,029	199,252	197,475	195,698	193,921	192,144	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		356	353	350	347	344	341	330	327	324	321	318	315	4,026
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		1,110	1,101	1,091	1,082	1,073	1,063	1,044	1,034	1,025	1,016	1,007	997	12,643
	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					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	0.9930%				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)					$3,570	$3,558	$3,545	$3,533	$3,521	$3,508	$3,478	$3,465	$3,453	$3,441	$3,429	$3,416	$41,917
	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					$3,570	$3,558	$3,545	$3,533	$3,521	$3,508	$3,478	$3,465	$3,453	$3,441	$3,429	$3,416	$41,917

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(18,339)	(18,441)	(18,543)	(18,645)	(18,747)	(18,849)	(18,951)	(19,053)	(19,155)	(19,257)	(19,359)	(19,461)	(19,563)	
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)				$14,753	$14,651	$14,549	$14,447	$14,345	$14,243	$14,141	$14,039	$13,937	$13,835	$13,733	$13,631	$13,529	
6	Average Net Investment					14,702	14,600	14,498	14,396	14,294	14,192	14,090	13,988	13,886	13,784	13,682	13,580	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		25	25	24	24	24	24	23	23	23	23	22	22	282
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		77	77	76	75	75	74	73	73	72	72	71	70	885
	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	0.1645%				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)					$209	$209	$207	$206	$206	$205	$203	$203	$202	$202	$200	$199	$2,451
	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					$209	$209	$207	$206	$206	$205	$203	$203	$202	$202	$200	$199	$2,451

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA
Envrionmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				$45,572	42,642	39,712	36,782	33,852	30,922	27,992	25,062	22,132	19,202	16,272	13,342	10,412	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$2,411,519	$2,408,589	$2,405,659	$2,402,729	$2,399,799	$2,396,869	$2,393,939	$2,391,009	$2,388,079	$2,385,149	$2,382,219	$2,379,289	$2,376,359	
6	Average Net Investment					2,410,054	2,407,124	2,404,194	2,401,264	2,398,334	2,395,404	2,392,474	2,389,544	2,386,614	2,383,684	2,380,754	2,377,824	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		4,052	4,047	4,042	4,038	4,033	4,028	3,923	3,918	3,913	3,909	3,904	3,899	47,706
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		12,635	12,620	12,605	12,589	12,574	12,559	12,420	12,404	12,389	12,374	12,359	12,344	149,872
	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	0.1645%				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)					$19,941	$19,921	$19,901	$19,881	$19,861	$19,841	$19,597	$19,576	$19,556	$19,537	$19,517	$19,497	$236,626
	a. Recoverable Costs Allocated to Energy					0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand					$19,941	$19,921	$19,901	$19,881	$19,861	$19,841	$19,597	$19,576	$19,556	$19,537	$19,517	$19,497	$236,626

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(72,786)	(73,311)	(73,836)	(74,361)	(74,886)	(75,411)	(75,936)	(76,461)	(76,986)	(77,511)	(78,036)	(78,561)	(79,086)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$217,512	$216,987	$216,462	$215,937	$215,412	$214,887	$214,362	$213,837	$213,312	$212,787	$212,262	$211,737	$211,212	
6	Average Net Investment					217,249	216,724	216,199	215,674	215,149	214,624	214,099	213,574	213,049	212,524	211,999	211,474	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		365	364	364	363	362	361	351	350	349	348	348	347	4,272
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		1,139	1,136	1,133	1,131	1,128	1,125	1,111	1,109	1,106	1,103	1,101	1,098	13,420
	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	0.8490%				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)					$2,234	$2,230	$2,227	$2,224	$2,220	$2,216	$2,192	$2,189	$2,185	$2,181	$2,179	$2,175	$26,452
	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					$2,234	$2,230	$2,227	$2,224	$2,220	$2,216	$2,192	$2,189	$2,185	$2,181	$2,179	$2,175	$26,452

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			$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			(43,337)	(43,741)	(44,145)	(44,549)	(44,953)	(45,357)	(45,761)	(46,165)	(46,569)	(46,973)	(47,377)	(47,781)	(48,185)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$118,417	$118,013	$117,609	$117,205	$116,801	$116,397	$115,993	$115,589	$115,185	$114,781	$114,377	$113,973	$113,569	
6	Average Net Investment				118,215	117,811	117,407	117,003	116,599	116,195	115,791	115,387	114,983	114,579	114,175	113,771	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		2.02%	1.97%	199	198	197	197	196	195	190	189	189	188	187	187	2,312
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%	620	618	616	613	611	609	601	599	597	595	593	591	7,263
	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	0.9420%			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)				$1,350	$1,347	$1,344	$1,341	$1,338	$1,335	$1,322	$1,319	$1,317	$1,314	$1,311	$1,309	$15,947
	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				$1,350	$1,347	$1,344	$1,341	$1,338	$1,335	$1,322	$1,319	$1,317	$1,314	$1,311	$1,309	$15,947

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(53,857)	(54,215)	(54,573)	(54,931)	(55,289)	(55,647)	(56,005)	(56,363)	(56,721)	(57,079)	(57,437)	(57,795)	(58,153)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$221,490	$221,132	$220,774	$220,416	$220,058	$219,700	$219,342	$218,984	$218,626	$218,268	$217,910	$217,552	$217,194	
6	Average Net Investment				221,311	220,953	220,595	220,237	219,879	219,521	219,163	218,805	218,447	218,089	217,731	217,373	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		2.02%	1.97%	372	372	371	370	370	369	359	359	358	358	357	356	4,371
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%	1,160	1,158	1,157	1,155	1,153	1,151	1,138	1,136	1,134	1,132	1,130	1,128	13,732
	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	0.9930%			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)				$2,118	$2,116	$2,114	$2,111	$2,109	$2,106	$2,083	$2,081	$2,078	$2,076	$2,073	$2,070	$25,135
	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				$2,118	$2,116	$2,114	$2,111	$2,109	$2,106	$2,083	$2,081	$2,078	$2,076	$2,073	$2,070	$25,135

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(47,871)	(48,255)	(48,639)	(49,023)	(49,407)	(49,791)	(50,175)	(50,559)	(50,943)	(51,327)	(51,711)	(52,095)	(52,479)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$151,117	$150,733	$150,349	$149,965	$149,581	$149,197	$148,813	$148,429	$148,045	$147,661	$147,277	$146,893	$146,509	
6	Average Net Investment				150,925	150,541	150,157	149,773	149,389	149,005	148,621	148,237	147,853	147,469	147,085	146,701	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		2.02%	1.97%	254	253	252	252	251	251	244	243	242	242	241	241	2,966
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%	791	789	787	785	783	781	772	770	768	766	764	762	9,318
	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	0.9930%			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)				$1,594	$1,591	$1,588	$1,586	$1,583	$1,581	$1,565	$1,562	$1,559	$1,557	$1,554	$1,552	$18,872
	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				$1,594	$1,591	$1,588	$1,586	$1,583	$1,581	$1,565	$1,562	$1,559	$1,557	$1,554	$1,552	$18,872

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			(27,399)	(27,618)	(27,837)	(28,056)	(28,275)	(28,494)	(28,713)	(28,932)	(29,151)	(29,370)	(29,589)	(29,808)	(30,027)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$60,268	$60,049	$59,830	$59,611	$59,392	$59,173	$58,954	$58,735	$58,516	$58,297	$58,078	$57,859	$57,640	
6	Average Net Investment				60,159	59,940	59,721	59,502	59,283	59,064	58,845	58,626	58,407	58,188	57,969	57,750	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		2.02%	1.97%	101	101	100	100	100	99	96	96	96	95	95	95	1,174
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%	315	314	313	312	311	310	305	304	303	302	301	300	3,690
	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	1.1630%			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)				$720	$719	$717	$716	$715	$713	$705	$704	$703	$701	$700	$699	$8,512
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$720	$719	$717	$716	$715	$713	$705	$704	$703	$701	$700	$699	$8,512

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				$347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	
3	Less: Accumulated Depreciation				(87,177)	(88,016)	(88,855)	(89,694)	(90,533)	(91,372)	(92,211)	(93,050)	(93,889)	(94,728)	(95,567)	(96,406)	(97,245)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$260,021	$259,182	$258,343	$257,504	$256,665	$255,826	$254,987	$254,148	$253,309	$252,470	$251,631	$250,792	$249,953	
6	Average Net Investment					259,601	258,762	257,923	257,084	256,245	255,406	254,567	253,728	252,889	252,050	251,211	250,372	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		436	435	434	432	431	429	417	416	415	413	412	411	5,081
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		1,361	1,357	1,352	1,348	1,343	1,339	1,321	1,317	1,313	1,308	1,304	1,300	15,963
	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	0.9930%				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)					$2,923	$2,918	$2,912	$2,906	$2,900	$2,894	$2,864	$2,859	$2,854	$2,847	$2,842	$2,837	$34,556
	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					$2,923	$2,918	$2,912	$2,906	$2,900	$2,894	$2,864	$2,859	$2,854	$2,847	$2,842	$2,837	$34,556

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				(95,011)	(95,798)	(96,585)	(97,372)	(98,159)	(98,946)	(99,733)	(100,520)	(101,307)	(102,094)	(102,881)	(103,668)	(104,455)	
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)				$254,573	$253,786	$252,999	$252,212	$251,425	$250,638	$249,851	$249,064	$248,277	$247,490	$246,703	$245,916	$245,129	
6	Average Net Investment					254,179	253,392	252,605	251,818	251,031	250,244	249,457	248,670	247,883	247,096	246,309	245,522	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		427	426	425	423	422	421	409	408	406	405	404	403	4,979
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		1,333	1,328	1,324	1,320	1,316	1,312	1,295	1,291	1,287	1,283	1,279	1,275	15,643
	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	0.8500%				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)					$2,795	$2,789	$2,784	$2,778	$2,773	$2,768	$2,739	$2,734	$2,728	$2,723	$2,718	$2,713	$33,042
	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					$2,795	$2,789	$2,784	$2,778	$2,773	$2,768	$2,739	$2,734	$2,728	$2,723	$2,718	$2,713	$33,042

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

DUKE ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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)				48,372	45,147	41,922	38,698	35,473	32,248	29,023	25,798	22,574	19,349	16,124	12,899	9,674	
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)				$48,372	$45,147	$41,922	$38,698	$35,473	$32,248	$29,023	$25,798	$22,574	$19,349	$16,124	$12,899	$9,674	
6	Average Net Investment					46,760	43,535	40,310	37,085	33,860	30,636	27,411	24,186	20,961	17,736	14,512	11,287	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		79	73	68	62	57	52	45	40	34	29	24	19	582
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		245	228	211	194	178	161	142	126	109	92	75	59	1,820
	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	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	3,225	38,698
	c. Dismantlement					N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	1.1630%				0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$3,549	$3,526	$3,504	$3,481	$3,460	$3,438	$3,412	$3,391	$3,368	$3,346	$3,324	$3,303	$41,100
	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					$3,549	$3,526	$3,504	$3,481	$3,460	$3,438	$3,412	$3,391	$3,368	$3,346	$3,324	$3,303	$41,100

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				($56,190)	(56,613)	(57,036)	(57,459)	(57,882)	(58,305)	(58,728)	(59,151)	(59,574)	(59,997)	(60,420)	(60,843)	(61,266)	
4	CWIP - Non-Interest Bearing				$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$325,370	$324,947	$324,524	$324,101	$323,678	$323,255	$322,832	$322,409	$321,986	$321,563	$321,140	$320,717	$320,294	
6	Average Net Investment					325,158	324,735	324,312	323,889	323,466	323,043	322,620	322,197	321,774	321,351	320,928	320,505	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		547	546	545	545	544	543	529	528	528	527	526	526	6,434
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		1,705	1,703	1,700	1,698	1,696	1,694	1,675	1,673	1,670	1,668	1,666	1,664	20,212
	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	0.8060%				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)					$2,931	$2,928	$2,924	$2,922	$2,919	$2,916	$2,883	$2,880	$2,877	$2,874	$2,871	$2,869	$34,794
	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					$2,931	$2,928	$2,924	$2,922	$2,919	$2,916	$2,883	$2,880	$2,877	$2,874	$2,871	$2,869	$34,794

(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
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$0	$0	$0	$0	$0	$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				($129,041)	(133,465)	(137,889)	(142,313)	(146,737)	(151,161)	(155,585)	(160,009)	(164,433)	(168,857)	(173,281)	(177,705)	(182,129)	
4	CWIP - Non-Interest Bearing				0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)				$2,020,059	$2,015,635	$2,011,211	$2,006,787	$2,002,363	$1,997,939	$1,993,515	$1,989,091	$1,984,667	$1,980,243	$1,975,819	$1,971,395	$1,966,971	
6	Average Net Investment					2,017,847	2,013,423	2,008,999	2,004,575	2,000,151	1,995,727	1,991,303	1,986,879	1,982,455	1,978,031	1,973,607	1,969,183	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		3,393	3,385	3,378	3,371	3,363	3,356	3,265	3,258	3,251	3,243	3,236	3,229	39,728
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		10,579	10,556	10,533	10,510	10,486	10,463	10,337	10,314	10,291	10,268	10,245	10,222	124,804
	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	0.1703%				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)					$18,701	$18,670	$18,640	$18,610	$18,578	$18,548	$18,331	$18,301	$18,271	$18,240	$18,210	$18,180	$221,280
	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					$18,701	$18,670	$18,640	$18,610	$18,578	$18,548	$18,331	$18,301	$18,271	$18,240	$18,210	$18,180	$221,280

For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)
(in Dollars)

Line	Description				Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																	
	a. Expenditures/Additions					$3,357,899	$3,068,868	$6,676,348	$2,974,452	$2,891,636	$4,028,331	$5,374,151	$5,527,579	$5,004,520	$3,127,296	$1,637,572	$1,331,905	$45,000,558
	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				$614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	614,010	
3	Less: Accumulated Depreciation				($34,043)	(34,803)	(35,563)	(36,323)	(37,083)	(37,843)	(38,603)	(39,363)	(40,123)	(40,883)	(41,643)	(42,403)	(43,163)	
4	CWIP - Non-Interest Bearing				30,270,290	33,628,190	36,697,058	43,373,406	46,347,858	49,239,494	53,267,824	58,641,976	64,169,555	69,174,075	72,301,371	73,938,944	75,270,849	
5	Net Investment (Lines 2 + 3 + 4)				$30,850,257	$34,207,397	$37,275,505	$43,951,093	$46,924,784	$49,815,661	$53,843,231	$59,216,623	$64,743,442	$69,747,202	$72,873,738	$74,510,550	$75,841,696	
6	Average Net Investment					32,528,827	35,741,451	40,613,299	45,437,939	48,370,223	51,829,446	56,529,927	61,980,032	67,245,322	71,310,470	73,692,144	75,176,123	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec														
	a. Debt Component		2.02%	1.97%		54,695	60,096	68,288	76,400	81,330	87,147	92,695	101,632	110,266	116,931	120,837	123,270	1,093,587
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%		170,542	187,385	212,927	238,221	253,595	271,731	293,453	321,745	349,077	370,180	382,543	390,247	3,441,646
	c. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																	
	a. Depreciation	1.4860%				760	760	760	760	760	760	760	760	760	760	760	760	9,120
	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	0.1703%				87	87	87	87	87	87	87	87	87	87	87	87	1,044
	e. Other					0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)					$226,084	$248,328	$282,062	$315,468	$335,772	$359,725	$386,995	$424,224	$460,190	$487,958	$504,227	$514,364	$4,545,397
	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					$226,084	$248,328	$282,062	$315,468	$335,772	$359,725	$386,995	$424,224	$460,190	$487,958	$504,227	$514,364	$4,545,397

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 (ECRC)
Capital Programs Detail Support - January 2018 through December 2018
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-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			($71,533)	(72,894)	(74,255)	(75,616)	(76,977)	(78,338)	(79,699)	(81,060)	(82,421)	(83,782)	(85,143)	(86,504)	(87,865)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$589,465	$588,104	$586,743	$585,382	$584,021	$582,660	$581,299	$579,938	$578,577	$577,216	$575,855	$574,494	$573,133	
6	Average Net Investment				588,785	587,424	586,063	584,702	583,341	581,980	580,619	579,258	577,897	576,536	575,175	573,814	
7	Return on Average Net Investment (A)		Jan-Jun	Jul-Dec													
	a. Debt Component		2.02%	1.97%	990	988	985	983	981	979	952	950	948	945	943	941	11,585
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%	3,087	3,080	3,073	3,065	3,058	3,051	3,014	3,007	3,000	2,993	2,986	2,979	36,393
	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	0.1703%			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)				$5,532	$5,523	$5,513	$5,503	$5,494	$5,485	$5,421	$5,412	$5,403	$5,393	$5,384	$5,375	$65,438
	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				$5,532	$5,523	$5,513	$5,503	$5,494	$5,485	$5,421	$5,412	$5,403	$5,393	$5,384	$5,375	$65,438

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4s) - CR5 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Actual Jan-18	Actual Feb-18	Actual Mar-18	Actual Apr-18	Actual May-18	Actual Jun-18	Estimated Jul-18	Estimated Aug-18	Estimated Sep-18	Estimated Oct-18	Estimated Nov-18	Estimated Dec-18	End of Period Total
1	Investments																
	a. Expenditures/Additions				$0	$0	$0	$0	$0	$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			($41,839)	(42,880)	(43,921)	(44,962)	(46,003)	(47,044)	(48,085)	(49,126)	(50,167)	(51,208)	(52,249)	(53,290)	(54,331)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$464,065	$463,024	$461,983	$460,942	$459,901	$458,860	$457,819	$456,778	$455,737	$454,696	$453,655	$452,614	$451,573	
6	Return on Average Net Investment (A)				463,545	462,504	461,463	460,422	459,381	458,340	457,299	456,258	455,217	454,176	453,135	452,094	
7	Return on Average Net Investment		Jan-Jun	Jul-Dec													
	a. Debt Component		2.02%	1.97%	779	778	776	774	772	771	750	748	746	745	743	741	9,123
	b. Equity Component Grossed Up For Taxes		6.29%	6.23%	2,430	2,425	2,419	2,414	2,408	2,403	2,374	2,368	2,363	2,358	2,352	2,347	28,661
	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	0.1703%			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)				$4,322	$4,316	$4,308	$4,301	$4,293	$4,287	$4,237	$4,229	$4,222	$4,216	$4,208	$4,201	$51,140
	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				$4,322	$4,316	$4,308	$4,301	$4,293	$4,287	$4,237	$4,229	$4,222	$4,216	$4,208	$4,201	$51,140

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
Commission Forms 42-1P Through 42-8P

January 2019 - December 2019
Calculation of Projected Period Amount

Docket No. 20180007-EI

FLORIDA PUBLIC SERVICE C
DOCKET: 20180007-EI EXHI
PARTY: DUKE ENERGY FLO
DESCRIPTION: Christopher M

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Commission Forms 42-1P Through 42-8P

January 2019 - December 2019
Calculation of Projected Period Amount

Docket No. 20180007-EI

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

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)	$38,716,265	$286,781	$8,314	$388,899	$39,400,259
	b Projected Capital Projects (Form 42-3P, Lines 7 through 9)	22,759,995	0	1,114	2,872,954	25,634,063
	c Total Jurisdictional Rev Req for the Projected Period (Lines 1a + 1b)	61,476,260	286,781	9,428	3,261,852	65,034,322
2	True-up for Estimated Over/(Under) Recovery for the Current Period January 2018 - December 2018 (Form 42-2E, Line 5 + 6 + 10)	3,285,584	(44,029)	(60,694)	1,263,334	4,444,195
3	Final True-up for the Period January 2017 - December 2017 (Form 42-1A, Line 3)	4,316,829	109,895	35,386	352,681	4,814,791
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection Period January 2019 - December 2019 (Line 1 - Line 2 - Line 3)	53,873,847	220,915	34,737	1,645,837	55,775,336
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$53,912,636	$221,074	$34,762	$1,647,022	$55,815,494

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

O&M Activities
(in Dollars)

Line		Description	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	End of Period Total
1		O&M Activities - System													
	1	Transmission Substation Environmental Investigation, Remediation and Pollution Prevention	$33,957	$34,067	$34,175	$34,080	$34,065	$34,082	$33,999	$34,043	$34,059	$34,014	$33,987	$33,975	$408,504
	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	2,000	0	0	2,000	0	0	2,000	0	0	2,000	8,000
	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	2,128	1,658	1,030	1,068	1,675	1,833	1,936	2,002	1,899	1,765	1,905	1,585	20,482
	6	Phase II Cooling Water Intake 316(b) - Base	0	26,700	0	26,700	0	26,700	0	26,700	0	26,700	0	26,700	160,200
	6a	Phase II Cooling Water Intake 316(b) - Intm	0	23,100	0	23,100	0	23,100	0	23,100	0	23,100	0	23,100	138,600
	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	1,561,483	1,476,583	1,452,583	1,307,783	1,334,783	1,215,683	1,215,683	1,215,683	1,215,683	1,215,683	1,215,683	1,214,783	15,642,100
	7.4	CAIR/CAMR Crystal River - Energy	1,601,769	1,403,283	1,136,206	1,152,727	1,412,678	1,481,623	1,526,625	1,555,454	1,511,630	1,454,052	1,514,214	1,377,126	17,127,387
	7.4	CAIR/CAMR Crystal River - A&G	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	125,297
	7.4	CAIR/CAMR Crystal River - Conditions of Certification - Energy	241,700	241,700	241,700	241,700	241,700	241,700	241,700	241,700	241,700	241,700	241,700	241,700	2,900,394
	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	0	37,500	0	0	37,500	0	0	37,500	0	0	37,500	150,000
	9	Sea Turtle - Coastal Street Lighting - Distrib	0	0	0	0	0	100	100	50	50	50	0	0	350
	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	9,500	5,500	5,100	0	0	0	5,500	0	0	25,600
	17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	48,000	598,000
	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	60,000	0	0	0	0	0	0	0	0	0	0	0	60,000
	18	Coal Combustion Residual (CCR) Rule - Energy	340,318	340,318	340,318	340,318	348,118	344,318	344,118	344,318	348,118	342,318	353,318	341,318	4,127,212
2		Total O&M Activities - Recoverable Costs	$3,901,796	$3,607,850	$3,305,953	$3,197,417	$3,438,960	$3,474,179	$3,424,601	$3,503,492	$3,453,080	$3,405,323	$3,421,247	$3,358,227	$41,492,125
3		Recoverable Costs Allocated to Energy	2,295,915	2,036,958	1,769,253	1,795,312	2,059,670	2,124,572	2,164,377	2,193,474	2,153,346	2,095,334	2,161,136	2,009,728	24,859,075
4		Recoverable Costs Allocated to Demand - Transm	33,957	34,067	34,175	34,080	34,065	34,082	33,999	34,043	34,059	34,014	33,987	33,975	408,504
		Recoverable Costs Allocated to Demand - Distrib	0	0	2,000	0	0	2,100	100	50	2,050	50	0	2,000	8,350
		Recoverable Costs Allocated to Demand - Prod-Base	1,561,483	1,503,283	1,490,083	1,334,483	1,334,783	1,279,883	1,215,683	1,242,383	1,253,183	1,242,383	1,215,683	1,278,983	15,952,300
		Recoverable Costs Allocated to Demand - Prod-Intm	0	23,100	0	23,100	0	23,100	0	23,100	0	23,100	0	23,100	138,600
		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	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	10,441	125,297
5		Retail Energy Jurisdictional Factor	0.97212	0.98260	0.97021	0.96633	0.96365	0.96146	0.96085	0.96182	0.96677	0.96888	0.97765	0.96721	
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)	2,231,908	2,001,516	1,716,545	1,734,860	1,984,809	2,042,689	2,079,640	2,109,733	2,081,800	2,030,137	2,112,833	1,943,828	24,070,298
8		Jurisdictional Demand Recoverable Costs - Transm (B)	23,839	23,916	23,992	23,925	23,915	23,927	23,868	23,899	23,910	23,879	23,860	23,851	286,781
		Jurisdictional Demand Recoverable Costs - Distrib (B)	0	0	1,991	0	0	2,091	100	50	2,041	50	0	1,991	8,314
		Jurisdictional Demand Recoverable Costs - Prod-Base (B)	1,450,384	1,396,325	1,384,064	1,239,535	1,239,813	1,188,820	1,129,187	1,153,988	1,164,019	1,153,988	1,129,187	1,187,984	14,817,294
		Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	0	16,794	0	16,794	0	16,794	0	16,794	0	16,794	0	16,794	100,764
		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)	9,734	9,734	9,734	9,734	9,734	9,734	9,734	9,734	9,734	9,734	9,734	9,734	116,808
9		Total Jurisdictional Recoverable Costs - O&M Activities (Lines 7 + 8)	$3,715,865	$3,448,285	$3,136,326	$3,024,848	$3,258,271	$3,284,055	$3,242,529	$3,314,198	$3,281,504	$3,234,582	$3,275,614	$3,184,182	$39,400,259

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 2019 - December 2019

Capital Investment Projects-Recoverable Costs
(in Dollars)

Form 42-3P

Docket No. 20180007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)

Line	Description	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	End of Period Total
1	Investment Projects - System (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline - Intm	$52,469	$52,141	$51,815	$51,488	$51,161	$50,834	$50,508	$50,187	$0	$0	$0	$0	$410,604
4.1	Above Ground Tank Secondary Containment - Peaking	120,374	119,893	119,423	73,369	73,187	73,003	72,821	72,636	72,454	72,268	72,087	71,903	1,013,418
4.2	Above Ground Tank Secondary Containment - Base	18,970	18,950	18,931	18,911	18,892	18,872	18,852	18,832	18,813	18,793	18,774	18,751	226,341
4.3	Above Ground Tank Secondary Containment - Intm	2,109	2,105	2,101	2,098	2,095	2,092	2,088	2,085	2,081	2,078	2,074	2,071	25,077
5	SO2/NOX Emissions Allowances - Energy	21,161	21,149	21,141	21,134	21,125	21,113	21,101	21,088	21,075	21,063	21,051	21,040	253,241
6	Phase II Cooling Water Intake 316(b) - Base	8,740	9,437	10,135	10,832	11,627	12,538	13,475	14,554	17,745	23,100	28,642	34,184	195,009
7.1	CAIR/CAMR Anclote- Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR/CAMR - Peaking	16,903	16,856	16,813	13,557	13,534	13,513	13,491	13,467	13,447	13,423	13,400	13,380	171,784
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	526,077	531,591	644,305	649,075	651,904	654,004	654,768	654,296	653,605	652,914	652,224	651,535	7,576,298
7.4	CAIR/CAMR Crystal River AFUDC - Energy	7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	92,111
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	92	92	92	92	92	92	93	94	95	95	95	95	1,119
10.1	Underground Storage Tanks - Base	1,219	1,218	1,216	1,214	1,212	1,210	1,208	1,206	1,204	1,203	1,200	1,198	14,508
10.2	Underground Storage Tanks - Intm	572	571	570	568	567	565	564	563	561	560	559	557	6,777
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	9,437	9,425	9,412	9,400	9,388	9,376	9,363	9,351	9,339	9,327	9,314	9,302	112,434
16	National Pollutant Discharge Elimination System (NPDES) - Intm	118,895	118,661	118,428	118,195	117,962	117,728	117,495	117,262	117,029	116,797	116,563	116,330	1,411,345
17	Mercury & Air Toxic Standards (MATS) CR4 & CR5 - Energy	28,860	28,818	28,775	28,731	28,689	28,645	28,603	28,559	28,516	28,474	28,430	28,388	343,492
17.1	Mercury & Air Toxic Standards (MATS) Anclote Gas Conversion - Energy	1,101,737	1,100,154	1,098,569	1,096,985	1,095,400	1,093,816	1,092,232	1,090,648	1,089,063	1,087,478	1,085,894	1,084,310	13,116,280
17.2	Mercury & Air Toxic Standards (MATS) CR1 & CR2 - Energy	191,023	190,566	190,108	189,652	189,194	188,737	188,281	187,823	187,366	186,909	186,452	185,995	2,262,111
18	Coal Combustion Residual (CCR) Rule - Base	3,432	3,522	3,613	3,703	3,793	3,884	3,974	4,064	4,155	4,245	4,335	4,426	47,146
2	Total Investment Projects - Recoverable Costs	$2,229,746	$2,232,825	$2,343,123	$2,296,680	$2,297,498	$2,297,698	$2,296,593	$2,294,391	$2,244,224	$2,246,403	$2,248,770	$2,251,141	$27,279,095
3	Recoverable Costs Allocated to Energy	1,350,457	1,348,363	1,346,269	1,344,178	1,342,084	1,339,987	1,337,893	1,335,794	1,333,696	1,331,600	1,329,503	1,327,409	16,067,235
	Recoverable Costs Allocated to Distribution Demand	92	92	92	92	92	92	93	94	95	95	95	95	1,119
4	Recoverable Costs Allocated to Demand - Production - Base	567,875	574,143	687,612	693,135	696,816	699,884	701,640	702,303	704,861	709,582	714,489	719,396	8,171,736
	Recoverable Costs Allocated to Demand - Production - Intermediate	174,045	173,478	172,914	172,349	171,785	171,219	170,655	170,097	119,671	119,435	119,196	118,958	1,853,803
	Recoverable Costs Allocated to Demand - Production - Peaking	137,277	136,749	136,236	86,926	86,721	86,516	86,312	86,103	85,901	85,691	85,487	85,283	1,185,202
5	Retail Energy Jurisdictional Factor	0.97212	0.98260	0.97021	0.96633	0.96365	0.96146	0.96085	0.96182	0.96677	0.96888	0.97765	0.96721	
	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)	1,312,808	1,324,902	1,306,162	1,298,917	1,293,305	1,288,343	1,285,514	1,284,797	1,289,383	1,290,167	1,299,788	1,283,883	15,557,968
	Jurisdictional Demand Recoverable Costs - Distribution (B)	92	92	92	92	92	92	93	94	95	95	95	95	1,114
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	527,471	533,293	638,688	643,818	647,238	650,087	651,718	652,334	654,710	659,095	663,653	668,211	7,590,317
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	126,536	126,124	125,714	125,303	124,893	124,481	124,071	123,665	87,004	86,833	86,659	86,486	1,347,770
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	131,682	131,175	130,683	83,383	83,186	82,990	82,794	82,593	82,400	82,198	82,003	81,807	1,136,893
9	Total Jurisdictional Recoverable Costs - Investment Projects (Lines 7 + 8)	$2,098,588	$2,115,586	$2,201,339	$2,151,513	$2,148,713	$2,145,992	$2,144,190	$2,143,483	$2,113,592	$2,118,388	$2,132,197	$2,120,481	$25,634,063

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9; Form 42-4P, Line 5 for Projects 5 - Emission Allowances and Project 7. 4 - Reagents.
(B) Line 3 x Line 5
(C) Line 4 x Line 6

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline - Intermediate (Project 3.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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 (A)		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3a	Regulatory Asset Balance (G)		400,142	350,124	300,107	250,090	200,073	150,056	100,039	50,021	(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	$300,107	$250,090	$200,073	$150,056	$100,039	$50,022	$0	$0	$0	$0	$0	
6	Average Net Investment			$375,133	$325,116	$275,099	$225,082	$175,065	$125,047	$75,030	$25,011	$0	$0	$0	$0	
7	Return on Average Net Investment (B)															
	a. Debt Component	2.08%		651	564	478	391	304	217	130	44	0	0	0	0	2,779
	b. Equity Component Grossed Up For Taxes	5.76%		1,801	1,560	1,320	1,080	840	600	361	121	0	0	0	0	7,683
	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	50,022	0	0	0	0	400,142
	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	$52,141	$51,815	$51,488	$51,161	$50,834	$50,508	$50,187	$0	$0	$0	$0	$410,604
	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	$52,141	$51,815	$51,488	$51,161	$50,834	$50,508	$50,187	$0	$0	$0	$0	$410,604
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	37,908	37,671	37,433	37,196	36,958	36,721	36,487	0	0	0	0	298,521
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$38,147	$37,908	$37,671	$37,433	$37,196	$36,958	$36,721	$36,487	$0	$0	$0	$0	$298,521

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(C) N/A
(D) N/A
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Projects 3.1b, 3.1c, and 3.1d amortized over three 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
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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 - Peaking (Project 4.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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		$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	$9,235,204	
3	Less: Accumulated Depreciation		($3,410,676)	($3,438,745)	($3,466,814)	($3,494,883)	($3,522,952)	($3,551,021)	($3,579,090)	($3,607,159)	($3,635,228)	($3,663,297)	($3,691,366)	($3,719,435)	($3,747,504)	
3a	Regulatory Asset Balance (G)		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)		$5,961,660	$5,887,884	$5,814,108	$5,740,321	$5,712,252	$5,684,183	$5,656,114	$5,628,045	$5,599,976	$5,571,907	$5,543,838	$5,515,769	$5,487,700	
6	Average Net Investment			$5,924,772	$5,850,996	$5,777,214	$5,726,286	$5,698,217	$5,670,148	$5,642,079	$5,614,010	$5,585,941	$5,557,872	$5,529,803	$5,501,734	
7	Return on Average Net Investment (B)															
	a. Debt Component	2.08%		10,284	10,157	10,029	9,940	9,891	9,842	9,794	9,744	9,697	9,648	9,600	9,550	118,176
	b. Equity Component Grossed Up For Taxes	5.76%		28,438	28,084	27,731	27,484	27,351	27,216	27,082	26,947	26,812	26,675	26,542	26,408	326,770
	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	336,828
	b. Amortization (G)			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 (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	94,512
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$120,374	$119,893	$119,423	$73,369	$73,187	$73,003	$72,821	$72,636	$72,454	$72,268	$72,087	$71,903	$1,013,418
	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			$120,374	$119,893	$119,423	$73,369	$73,187	$73,003	$72,821	$72,636	$72,454	$72,268	$72,087	$71,903	$1,013,418
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)			115,468	115,006	114,555	70,378	70,204	70,027	69,853	69,675	69,501	69,322	69,149	68,972	972,111
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$115,468	$115,006	$114,555	$70,378	$70,204	$70,027	$69,853	$69,675	$69,501	$69,322	$69,149	$68,972	$972,111

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Project 4.1a amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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 - Base (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		4,145	4,140	4,135	4,130	4,125	4,120	4,114	4,109	4,104	4,099	4,094	4,087	49,402
	b. Equity Component Grossed Up For Taxes	5.76%		11,464	11,449	11,435	11,420	11,406	11,391	11,377	11,362	11,348	11,333	11,319	11,303	136,607
	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)			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
9	Total System Recoverable Expenses (Lines 7 + 8)			$18,970	$18,950	$18,931	$18,911	$18,892	$18,872	$18,852	$18,832	$18,813	$18,793	$18,774	$18,751	$226,341
	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			$18,970	$18,950	$18,931	$18,911	$18,892	$18,872	$18,852	$18,832	$18,813	$18,793	$18,774	$18,751	$226,341
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)			17,620	17,602	17,584	17,565	17,548	17,529	17,511	17,492	17,474	17,456	17,438	17,417	210,237
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$17,620	$17,602	$17,584	$17,565	$17,548	$17,529	$17,511	$17,492	$17,474	$17,456	$17,438	$17,417	$210,237

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)		$211,212	$210,687	$210,162	$209,637	$209,112	$208,587	$208,062	$207,537	$207,012	$206,487	$205,962	$205,437	$204,912	
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)															
	a. Debt Component	2.08%		366	365	364	363	363	362	361	360	359	358	357	356	4,334
	b. Equity Component Grossed Up For Taxes	5.76%		1,013	1,010	1,007	1,005	1,002	1,000	997	995	992	990	987	985	11,983
	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)			$2,109	$2,105	$2,101	$2,098	$2,095	$2,092	$2,088	$2,085	$2,081	$2,078	$2,074	$2,071	$25,077
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$2,109	$2,105	$2,101	$2,098	$2,095	$2,092	$2,088	$2,085	$2,081	$2,078	$2,074	$2,071	$25,077
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)			1,533	1,530	1,527	1,525	1,523	1,521	1,518	1,516	1,513	1,511	1,508	1,506	18,232
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,533	$1,530	$1,527	$1,525	$1,523	$1,521	$1,518	$1,516	$1,513	$1,511	$1,508	$1,506	$18,232

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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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Docket No. 20180007-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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	End of Period Total
1	Working Capital Dr (Cr)															
	a. 0158150 SO_2 Emission Allowance Inventory		$3,239,111	$3,236,950	$3,235,260	$3,234,197	$3,233,097	$3,231,389	$3,229,524	$3,227,556	$3,225,520	$3,223,588	$3,221,791	$3,219,853	$3,218,236	$3,218,236
	b. 0254020 Auctioned SO_2 Allowance		(216)	(184)	(151)	(118)	(85)	(52)	(19)	13	46	79	112	145	178	178
	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		$3,238,895	$3,236,767	$3,235,109	$3,234,079	$3,233,012	$3,231,337	$3,229,505	$3,227,569	$3,225,567	$3,223,667	$3,221,903	$3,219,998	$3,218,413	$3,218,413
3	Average Net Investment			$3,237,831	$3,235,938	$3,234,594	$3,233,546	$3,232,175	$3,230,421	$3,228,537	$3,226,568	$3,224,617	$3,222,785	$3,220,950	$3,219,206	
4	Return on Average Net Working Capital Balance (B)															
	a. Debt Component	2.08%		5,620	5,617	5,615	5,613	5,611	5,607	5,604	5,601	5,597	5,594	5,591	5,588	67,258
	b. Equity Component Grossed Up For Taxes	5.76%		15,541	15,532	15,526	15,521	15,514	15,506	15,497	15,487	15,478	15,469	15,460	15,452	185,983
5	Total Return Component (C)			$21,161	$21,149	$21,141	$21,134	$21,125	$21,113	$21,101	$21,088	$21,075	$21,063	$21,051	$21,040	253,241
6	Expense Dr (Cr)															
	a. 0509030 SO_2 Allowance Expense			$2,161	$1,690	$1,062	$1,101	$1,707	$1,865	$1,968	$2,035	$1,932	$1,798	$1,937	$1,618	20,876
	b. 0407426 Amortization Expense			(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(394)
	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)			2,128	1,658	1,030	1,068	1,675	1,833	1,936	2,002	1,899	1,765	1,905	1,585	20,482
8	Total System Recoverable Expenses (Lines 5 + 7)			$23,289	$22,807	$22,171	$22,202	$22,800	$22,946	$23,037	$23,090	$22,974	$22,828	$22,956	$22,625	273,723
	a. Recoverable costs allocated to Energy			$23,289	$22,807	$22,171	$22,202	$22,800	$22,946	$23,037	$23,090	$22,974	$22,828	$22,956	$22,625	273,723
	b. Recoverable costs allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
9	Energy Jurisdictional Factor			0.97212	0.98260	0.97021	0.96633	0.96365	0.96146	0.96085	0.96182	0.96677	0.96888	0.97765	0.96721	
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)			$22,640	$22,410	$21,510	$21,454	$21,971	$22,061	$22,135	$22,209	$22,211	$22,118	$22,442	$21,883	265,043
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)			$ 22,640	$ 22,410	$ 21,510	$ 21,454	$ 21,971	$ 22,061	$ 22,135	$ 22,209	$ 22,211	$ 22,118	$ 22,442	$ 21,883	$ 265,043

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	End of Period Total
1	Investments															
	a. Expenditures/Additions			$106,657	$106,657	$106,657	$106,657	$136,832	$141,973	$144,547	$185,811	$790,815	$847,912	$847,912	$847,912	$4,370,340
	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		1,283,982	1,390,639	1,497,295	1,603,952	1,710,609	1,847,441	1,989,414	2,133,961	2,319,772	3,110,587	3,958,498	4,806,410	5,654,322	
5	Net Investment (Lines 2 + 3 + 4)		$1,283,982	$1,390,639	$1,497,295	$1,603,952	$1,710,609	$1,847,441	$1,989,414	$2,133,961	$2,319,772	$3,110,587	$3,958,498	$4,806,410	$5,654,322	
6	Average Net Investment			$1,337,310	$1,443,967	$1,550,624	$1,657,280	$1,779,025	$1,918,427	$2,061,687	$2,226,866	$2,715,179	$3,534,542	$4,382,454	$5,230,366	
7	Return on Average Net Investment (B)															
	a. Debt Component	2.08%		2,321	2,506	2,692	2,877	3,088	3,330	3,579	3,865	4,713	6,135	7,607	9,079	51,792
	b. Equity Component Grossed Up For Taxes	5.76%		6,419	6,931	7,443	7,955	8,539	9,208	9,896	10,689	13,032	16,965	21,035	25,105	143,217
	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)	0.001703		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)			$8,740	$9,437	$10,135	$10,832	$11,627	$12,538	$13,475	$14,554	$17,745	$23,100	$28,642	$34,184	195,009
	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			8,740	9,437	10,135	10,832	11,627	12,538	13,475	14,554	17,745	23,100	28,642	34,184	195,009
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)			8,118	8,766	9,414	10,061	10,800	11,646	12,516	13,518	16,482	21,456	26,604	31,752	181,133
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$8,118	$8,766	$9,414	$10,061	$10,800	$11,646	$12,516	$13,518	$16,482	$21,456	$26,604	$31,752	$181,133

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-EI
Duke Energy Florida, LLC
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	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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		$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	$1,802,096	
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)	(492,777)	
3a	Regulatory Asset Balance (G)		9,674	6,449	3,224	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)		$1,359,962	$1,353,323	$1,346,684	$1,340,046	$1,336,632	$1,333,218	$1,329,804	$1,326,390	$1,322,976	$1,319,562	$1,316,148	$1,312,734	$1,309,320	
6	Average Net Investment			$1,356,642	$1,350,003	$1,343,365	$1,338,339	$1,334,925	$1,331,511	$1,328,097	$1,324,683	$1,321,269	$1,317,855	$1,314,441	$1,311,027	
7	Return on Average Net Investment (B)															
	a. Debt Component	2.08%		2,356	2,342	2,331	2,324	2,316	2,312	2,306	2,298	2,294	2,287	2,281	2,277	27,724
	b. Equity Component Grossed Up For Taxes	5.76%		6,512	6,479	6,448	6,423	6,408	6,391	6,375	6,359	6,343	6,326	6,309	6,293	76,666
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			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	3,224	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)			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)			$16,903	$16,856	$16,813	$13,557	$13,534	$13,513	$13,491	$13,467	$13,447	$13,423	$13,400	$13,380	171,784
	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			$16,903	$16,856	$16,813	$13,557	$13,534	$13,513	$13,491	$13,467	$13,447	$13,423	$13,400	$13,380	171,784
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)			16,214	16,169	16,128	13,004	12,982	12,962	12,941	12,918	12,899	12,876	12,854	12,835	164,782
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$16,214	$16,169	$16,128	$13,004	$12,982	$12,962	$12,941	$12,918	$12,899	$12,876	$12,854	$12,835	$164,782

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Project 7.2g amortized over three years as approved in Order No. PSC-2016-0535-FOF-EI.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR - Base (Project 7.4 - Crystal River)
(in Dollars)

Docket No. 20180007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	End of Period Total
1	Investments															
	a. Expenditures/Additions			$834,226	$868,932	$859,616	$568,540	$355,994	$350,116	$66,587	$0	$0	$0	$0	$0	$3,904,011
	b. Clearings to Plant			0	0	77,833,623	568,540	355,994	350,116	66,587	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		$3,930,012	$3,930,012	$3,930,012	$81,763,635	$82,332,175	$82,688,169	$83,038,285	$83,104,872	$83,104,872	$83,104,872	$83,104,872	$83,104,872	$83,104,872	
3	Less: Accumulated Depreciation		($367,488)	($375,074)	($382,660)	($486,630)	($591,304)	($696,419)	($801,968)	($907,599)	($1,013,230)	($1,118,861)	($1,224,492)	($1,330,123)	($1,435,754)	
4	CWIP - Non-Interest Bearing		75,270,849	76,105,075	76,974,007	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$78,833,373	$79,660,013	$80,521,359	$81,277,005	$81,740,871	$81,991,750	$82,236,317	$82,197,273	$82,091,642	$81,986,011	$81,880,380	$81,774,749	$81,669,118	
6	Average Net Investment			$79,246,693	$80,090,686	$80,899,182	$81,508,938	$81,866,311	$82,114,034	$82,216,795	$82,144,458	$82,038,827	$81,933,196	$81,827,565	$81,721,934	
7	Return on Average Net Investment (B)															
	a. Debt Component	2.08%		137,559	139,024	140,427	141,486	142,107	142,536	142,715	142,589	142,405	142,222	142,039	141,856	1,696,965
	b. Equity Component Grossed Up For Taxes	5.76%		380,374	384,423	388,305	391,231	392,947	394,135	394,628	394,282	393,775	393,267	392,760	392,254	4,692,381
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			7,586	7,586	103,970	104,674	105,115	105,549	105,631	105,631	105,631	105,631	105,631	105,631	1,068,266
	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	558	11,603	11,684	11,735	11,784	11,794	11,794	11,794	11,794	11,794	11,794	118,686
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$526,077	$531,591	$644,305	$649,075	$651,904	$654,004	$654,768	$654,296	$653,605	$652,914	$652,224	$651,535	7,576,298
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$526,077	$531,591	$644,305	$649,075	$651,904	$654,004	$654,768	$654,296	$653,605	$652,914	$652,224	$651,535	7,576,298
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)			488,647	493,768	598,463	602,893	605,521	607,472	608,181	607,743	607,101	606,459	605,818	605,178	7,037,244
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$488,647	$493,768	$598,463	$602,893	$605,521	$607,472	$608,181	$607,743	$607,101	$606,459	$605,818	$605,178	$7,037,244

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
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Docket No. 20180007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	End of Period Total
1	Working Capital Dr (Cr)															
	a. 0154401 Ammonia Inventory		$89,922	$89,922	$89,922	$89,922	$89,922	$89,922	$89,922	$89,922	$89,922	$89,922	$89,922	$89,922	$89,922	89,922
	b. 0154200 Limestone Inventory		$1,084,539	1,084,539	1,084,539	1,084,539	1,084,539	1,084,539	1,084,539	1,084,539	1,084,539	1,084,539	1,084,539	1,084,539	1,084,539	1,084,539
2	Total Working Capital		$1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461
3	Average Net Investment			1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	1,174,461	
4	Return on Average Net Working Capital Balance (A)															
	a. Debt Component	2.08%		2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	$24,464
	b. Equity Component Grossed Up For Taxes	5.76%		5,637	5,637	5,637	5,637	5,637	5,637	5,637	5,637	5,637	5,637	5,637	5,637	67,647
5	Total Return Component (B)			7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	7,676	92,111
6	Expense Dr (Cr)															
	a. 0502010 Ammonia Expense			391,667	391,667	391,667	391,667	391,667	391,667	391,667	391,667	391,667	391,667	391,667	391,667	4,700,000
	b. 0502040 Limestone Expense			683,574	536,217	337,341	349,716	543,765	595,551	629,362	650,929	618,329	575,332	620,328	517,962	6,658,407
	c. 0502050 Dibasic Acid Expense			6,667	6,667	6,667	6,667	6,667	6,667	6,667	6,667	6,667	6,667	6,667	6,667	80,000
	d. 0502070 Gypsum Disposal/Sale			234,695	183,566	115,365	119,511	185,413	202,572	213,763	221,025	209,801	195,221	210,386	175,663	2,266,980
	e. 0502040 Hydrated Lime Expense			283,333	283,333	283,333	283,333	283,333	283,333	283,333	283,333	283,333	283,333	283,333	283,333	3,400,000
	f. 0502300 Caustic Expense			1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	1,833	22,000
7	Net Expense (C)			1,601,769	1,403,283	1,136,206	1,152,727	1,412,678	1,481,623	1,526,625	1,555,454	1,511,630	1,454,052	1,514,214	1,377,126	17,127,387
8	Total System Recoverable Expenses (Lines 5 + 7)			$1,609,445	$1,410,959	$1,143,882	$1,160,403	$1,420,354	$1,489,298	$1,534,301	$1,563,130	$1,519,306	$1,461,728	$1,521,890	$1,384,802	$17,219,498
	a. Recoverable Costs Allocated to Energy			1,609,445	1,410,959	1,143,882	1,160,403	1,420,354	1,489,298	1,534,301	1,563,130	1,519,306	1,461,728	1,521,890	1,384,802	17,219,498
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Energy Jurisdictional Factor			0.97212	0.98260	0.97021	0.96633	0.96365	0.96146	0.96085	0.96182	0.96677	0.96888	0.97765	0.96721	
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)			1,564,576	1,386,409	1,109,805	1,121,330	1,368,730	1,431,899	1,474,232	1,503,454	1,468,826	1,416,246	1,487,874	1,339,393	16,672,773
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)			$ 1,564,576	$ 1,386,409	$ 1,109,805	$ 1,121,330	$ 1,368,730	$ 1,431,899	$ 1,474,232	$ 1,503,454	$ 1,468,826	$ 1,416,246	$ 1,487,874	$ 1,339,393	$ 16,672,773

Notes:

(A) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). See Stipulation & Settlement Agreement in Order No. PSC-2012-0425-PAA-EU Docket No. 20120007-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description	Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$50	$100	$100	$100	$50	$0	$0	$400
	b. Clearings to Plant		0	0	0	0	0	50	100	100	100	50	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	$11,924	11,924	11,924	11,924	11,924	11,924	11,974	12,074	12,174	12,274	12,324	12,324	12,324	
3	Less: Accumulated Depreciation	(3,703)	(3,733)	(3,763)	(3,793)	(3,823)	(3,853)	(3,883)	(3,914)	(3,945)	(3,976)	(4,007)	(4,038)	(4,069)	
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)	$8,221	$8,191	$8,161	$8,131	$8,101	$8,071	$8,091	$8,160	$8,229	$8,298	$8,317	$8,286	$8,255	
6	Average Net Investment		$8,206	$8,176	$8,146	$8,116	$8,086	$8,081	$8,126	$8,195	$8,264	$8,308	$8,302	$8,271	
7	Return on Average Net Investment (B)														
	a. Debt Component 2.08%		14	14	14	14	14	14	14	14	14	14	14	14	168
	b. Equity Component Grossed Up For Taxes 5.76%		39	39	39	39	39	39	39	39	40	40	40	40	472
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.0658%		30	30	30	30	30	30	31	31	31	31	31	31	366
	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) 0.009414	9	9	9	9	9	9	9	10	10	10	10	10	10	113
	e. Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)	$92	$92	$92	$92	$92	$92	$93	$94	$95	$95	$95	$95	$95	1,119
	a. Recoverable Costs Allocated to Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand	$92	$92	$92	$92	$92	$92	$93	$94	$95	$95	$95	$95	$95	1,119
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 - (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	0.99561	
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)	92	92	92	92	92	92	93	94	95	95	95	95	95	1,114
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)	$92	$92	$92	$92	$92	$92	$93	$94	$95	$95	$95	$95	$95	$1,114

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		213	213	212	212	211	211	210	210	209	209	208	207	2,525
	b. Equity Component Grossed Up For Taxes	5.76%		589	588	587	585	584	582	581	579	578	577	575	574	6,979
	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)			$1,219	$1,218	$1,216	$1,214	$1,212	$1,210	$1,208	$1,206	$1,204	$1,203	$1,200	$1,198	14,508
	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			$1,219	$1,218	$1,216	$1,214	$1,212	$1,210	$1,208	$1,206	$1,204	$1,203	$1,200	$1,198	14,508
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)			1,132	1,131	1,129	1,128	1,126	1,124	1,122	1,120	1,118	1,117	1,115	1,113	13,476
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,132	$1,131	$1,129	$1,128	$1,126	$1,124	$1,122	$1,120	$1,118	$1,117	$1,115	$1,113	$13,476

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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: UNDERGROUND STORAGE TANKS - Intermediate (10.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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 (A)			0	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)																
	a. Debt Component	2.08%		81	81	81	80	80	79	79	79	78	78	78	77	951	
	b. Equity Component Grossed Up For Taxes	5.76%		225	224	223	222	221	220	219	218	217	216	215	214	2,634	
	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		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)			$572	$571	$570	$568	$567	$565	$564	$563	$561	$560	$559	$557	6,777	
	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			$572	$571	$570	$568	$567	$565	$564	$563	$561	$560	$559	$557	6,777	
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)			416	415	414	413	412	411	410	409	408	407	406	405	4,927	
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$416	$415	$414	$413	$412	$411	$410	$409	$408	$407	$406	$405	$4,927	

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
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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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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			911,372	0	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	911,372	911,372	911,372	911,372	911,372	911,372	911,372	911,372	911,372	911,372	911,372	911,372	
3	Less: Accumulated Depreciation		0	(1,876)	(3,752)	(5,628)	(7,504)	(9,380)	(11,256)	(13,132)	(15,008)	(16,884)	(18,760)	(20,636)	(22,512)	
4	CWIP - Non-Interest Bearing		1,138,140	226,768	226,768	226,768	226,768	226,768	226,768	226,768	226,768	226,768	226,768	226,768	226,768	
5	Net Investment (Lines 2 + 3 + 4)		$1,138,140	$1,136,264	$1,134,388	$1,132,512	$1,130,636	$1,128,760	$1,126,884	$1,125,008	$1,123,132	$1,121,256	$1,119,380	$1,117,504	$1,115,628	
6	Average Net Investment			$1,137,202	$1,135,326	$1,133,450	$1,131,574	$1,129,698	$1,127,822	$1,125,946	$1,124,070	$1,122,194	$1,120,318	$1,118,442	$1,116,566	
7	Return on Average Net Investment (B)															
	a. Debt Component	2.08%		1,974	1,971	1,967	1,964	1,961	1,958	1,954	1,951	1,948	1,945	1,941	1,938	23,472
	b. Equity Component Grossed Up For Taxes	5.76%		5,458	5,449	5,440	5,431	5,422	5,413	5,404	5,395	5,386	5,377	5,368	5,359	64,902
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.4700%		1,876	1,876	1,876	1,876	1,876	1,876	1,876	1,876	1,876	1,876	1,876	1,876	22,512
	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		129	129	129	129	129	129	129	129	129	129	129	129	1,548
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$9,437	$9,425	$9,412	$9,400	$9,388	$9,376	$9,363	$9,351	$9,339	$9,327	$9,314	$9,302	112,434
	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			9,437	9,425	9,412	9,400	9,388	9,376	9,363	9,351	9,339	9,327	9,314	9,302	112,434
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)			8,766	8,754	8,742	8,731	8,720	8,709	8,697	8,686	8,675	8,663	8,651	8,640	104,434
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$8,766	$8,754	$8,742	$8,731	$8,720	$8,709	$8,697	$8,686	$8,675	$8,663	$8,651	$8,640	$104,434

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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: NPDES - Intermediate (Project 16)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		19,281	19,219	19,157	19,095	19,033	18,971	18,909	18,847	18,785	18,724	18,662	18,600	227,283
	b. Equity Component Grossed Up For Taxes	5.76%		53,315	53,143	52,972	52,801	52,630	52,458	52,287	52,116	51,945	51,774	51,602	51,431	628,474
	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)	0.009930		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)			$118,895	$118,661	$118,428	$118,195	$117,962	$117,728	$117,495	$117,262	$117,029	$116,797	$116,563	$116,330	1,411,345
	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			$118,895	$118,661	$118,428	$118,195	$117,962	$117,728	$117,495	$117,262	$117,029	$116,797	$116,563	$116,330	1,411,345
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)			86,440	86,270	86,101	85,931	85,762	85,592	85,422	85,253	85,084	84,915	84,745	84,575	1,026,090
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$86,440	$86,270	$86,101	$85,931	$85,762	$85,592	$85,422	$85,253	$85,084	$84,915	$84,745	$84,575	$1,026,090

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Docket No. 20180007-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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		5,936	5,925	5,914	5,902	5,891	5,879	5,868	5,856	5,845	5,834	5,822	5,811	70,483
	b. Equity Component Grossed Up For Taxes	5.76%		16,415	16,384	16,352	16,320	16,289	16,257	16,226	16,194	16,162	16,131	16,099	16,068	194,897
	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)	0.001703		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)			$28,860	$28,818	$28,775	$28,731	$28,689	$28,645	$28,603	$28,559	$28,516	$28,474	$28,430	$28,388	343,492
	a. Recoverable Costs Allocated to Energy			28,860	28,818	28,775	28,731	28,689	28,645	28,603	28,559	28,516	28,474	28,430	28,388	343,492
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.97212	0.98260	0.97021	0.96633	0.96365	0.96146	0.96085	0.96182	0.96677	0.96888	0.97765	0.96721	
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)			$28,056	$28,317	$27,918	$27,764	$27,647	$27,541	$27,484	$27,469	$27,569	$27,588	$27,795	$27,457	$332,605
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)			$28,056	$28,317	$27,918	$27,764	$27,647	$27,541	$27,484	$27,469	$27,569	$27,588	$27,795	$27,457	$332,605

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 Projection Amount
January 2019 - December 2019

Docket No. 20180007-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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		206,995	206,575	206,154	205,733	205,312	204,891	204,471	204,050	203,629	203,208	202,787	202,367	2,456,172
	b. Equity Component Grossed Up For Taxes	5.76%		572,375	571,212	570,048	568,885	567,721	566,558	565,394	564,231	563,067	561,903	560,740	559,576	6,791,710
	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)	0.008490		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)			$1,101,737	$1,100,154	$1,098,569	$1,096,985	$1,095,400	$1,093,816	$1,092,232	$1,090,648	$1,089,063	$1,087,478	$1,085,894	$1,084,310	13,116,280
	a. Recoverable Costs Allocated to Energy			1,101,737	1,100,154	1,098,569	1,096,985	1,095,400	1,093,816	1,092,232	1,090,648	1,089,063	1,087,478	1,085,894	1,084,310	13,116,280
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.97212	0.98260	0.97021	0.96633	0.96365	0.96146	0.96085	0.96182	0.96677	0.96888	0.97765	0.96721	
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)			$1,071,022	$1,081,011	$1,065,841	$1,060,047	$1,055,586	$1,051,659	$1,049,470	$1,049,009	$1,052,878	$1,053,640	$1,061,623	$1,048,755	$12,700,541
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)			$1,071,022	$1,081,011	$1,065,841	$1,060,047	$1,055,586	$1,051,659	$1,049,470	$1,049,009	$1,052,878	$1,053,640	$1,061,623	$1,048,755	$12,700,541

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 Projection Amount
January 2019 - December 2019

Docket No. 20180007-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 1 & 2 - Energy (Project 17.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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		$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		(2,998,529)	(3,068,462)	(3,138,395)	(3,208,328)	(3,278,261)	(3,348,194)	(3,418,127)	(3,488,060)	(3,557,993)	(3,627,926)	(3,697,859)	(3,767,792)	(3,837,725)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$19,682,545	$19,612,612	$19,542,679	$19,472,746	$19,402,813	$19,332,880	$19,262,947	$19,193,014	$19,123,081	$19,053,148	$18,983,215	$18,913,282	$18,843,349	
6	Average Net Investment			$19,647,578	$19,577,645	$19,507,712	$19,437,779	$19,367,846	$19,297,913	$19,227,980	$19,158,047	$19,088,114	$19,018,181	$18,948,248	$18,878,315	
7	Return on Average Net Investment (B)															
	a. Debt Component	2.08%		34,105	33,984	33,862	33,741	33,619	33,498	33,377	33,255	33,134	33,012	32,891	32,770	401,248
	b. Equity Component Grossed Up For Taxes	5.76%		94,306	93,970	93,634	93,299	92,963	92,627	92,292	91,956	91,620	91,285	90,949	90,613	1,109,514
	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)	0.001703		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)			$191,023	$190,566	$190,108	$189,652	$189,194	$188,737	$188,281	$187,823	$187,366	$186,909	$186,452	$185,995	2,262,111
	a. Recoverable Costs Allocated to Energy			191,023	190,566	190,108	189,652	189,194	188,737	188,281	187,823	187,366	186,909	186,452	185,995	2,262,111
	b. Recoverable Costs Allocated to Demand			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
10	Energy Jurisdictional Factor			0.97212	0.98260	0.97021	0.96633	0.96365	0.96146	0.96085	0.96182	0.96677	0.96888	0.97765	0.96721	
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)			$185,698	$187,251	$184,445	$183,266	$182,318	$181,463	$180,910	$180,653	$181,141	$181,094	$182,285	$179,897	$2,190,421
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)			$185,698	$187,251	$184,445	$183,266	$182,318	$181,463	$180,910	$180,653	$181,141	$181,094	$182,285	$179,897	$2,190,421

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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 Projection Amount
January 2019 - December 2019

Docket No. 20180007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
Page 22 of 48

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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	End of Period Total
1	Investments															
	a. Expenditures/Additions			$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$168,000
	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 (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	97,585	
3	Less: Accumulated Depreciation (A)		($4,224)	(4,400)	(4,576)	(4,752)	(4,928)	(5,104)	(5,280)	(5,456)	(5,632)	(5,808)	(5,984)	(6,160)	(6,336)	
4	CWIP - Non-Interest Bearing		395,755	409,755	423,755	437,755	451,755	465,755	479,755	493,755	507,755	521,755	535,755	549,755	563,755	
5	Net Investment (Lines 2 + 3 + 4)		$489,116	$502,940	$516,764	$530,588	$544,412	$558,236	$572,060	$585,884	$599,708	$613,532	$627,356	$641,180	$655,004	
6	Average Net Investment			$496,028	$509,852	$523,676	$537,500	$551,324	$565,148	$578,972	$592,796	$606,620	$620,444	$634,268	$648,092	
7	Return on Average Net Investment (B)															
	a. Debt Component	2.08%		861	885	909	933	957	981	1,005	1,029	1,053	1,077	1,101	1,125	11,916
	b. Equity Component Grossed Up For Taxes	5.76%		2,381	2,447	2,514	2,580	2,646	2,713	2,779	2,845	2,912	2,978	3,044	3,111	32,950
	c. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	2.1695%		176	176	176	176	176	176	176	176	176	176	176	176	2,112
	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		14	14	14	14	14	14	14	14	14	14	14	14	168
	e. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$3,432	$3,522	$3,613	$3,703	$3,793	$3,884	$3,974	$4,064	$4,155	$4,245	$4,335	$4,426	47,146
	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			3,432	3,522	3,613	3,703	3,793	3,884	3,974	4,064	4,155	4,245	4,335	4,426	47,146
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)			3,188	3,271	3,356	3,440	3,523	3,608	3,691	3,775	3,859	3,943	4,027	4,111	43,792
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$3,188	$3,271	$3,356	$3,440	$3,523	$3,608	$3,691	$3,775	$3,859	$3,943	$4,027	$4,111	$43,792

Notes:

(A) N/A
(B) Line 6 x 7.84% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.30% and statutory income tax rate of 25.345% (inc tax multiplier = 1.339495). 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 2017 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:
As of the end of second quarter 2018, a total of 272 substation remediations are completed out of 279 slated for clean-up.

Project Fiscal Expenditures:
2018 O&M expenditures for the substation system program are estimated to be $856k, which is $174k or 25% higher than originally projected. The variance is primarily due to higher than anticipated remediation costs at Central Florida Substation than initially projected, and remediation work at the Kenneth City Substation coming in higher than originally estimated due to more contaminated soil excavated once the breaker/control house was removed.

Project Progress Summary:
DEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan (SARAP).

Project Projections:
2019 O&M estimated expenditures are $409k.

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. Groundwater monitoring is in process.

Project Fiscal Expenditures:
There is $8K forecasted for 2018.

Project Progress Summary:
This project is complete with the exception of the groundwater monitoring at the 7100 Sunset Way, St. Petersburg Beach location.

Project Projections:
2019 O&M expenditures are expected to be $8k.

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 will be amortized over 26 months, and all four parts of this project will be fully amortized as of September 2019.

Project Fiscal Expenditures:
No capital or O&M expenditures are estimated for 2018.

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 will be fully amortized as of September 2019.

Project Projections:
No capital or O&M expenditures are estimated for 2019.

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 2018.

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. Consistent with DEF's petition filed August 4, 2016, DEF is treating the unrecovered investments as a regulatory asset, amortizing it over three years beginning April 2016 until fully recovered in 2019,with a return on the return on the unamortized balance.

Project Projections:
No project expenditures are expected in 2019.

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:
2018 O&M is forecasted to be $38k.

Project Progress Summary:
DEF continually evaluates the status of emission rules to maximize the cost effectiveness of its compliance strategy.

Project Projections:
2019 O&M expenditures are projected to be $21k.

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:
2018 O&M expenditures are estimated to be $265k. 2018 Capital expenditures are estimated to be $621k.

Project Progress Summary:
Initial steps in site specific plan development have been completed. Work continues on plans for implementation, decision milestones, compliance approaches, and study requirements. Procurement of long lead time equipment and material in 2018, and selection of contractor services for the Crystal River Project.

Project Projections:
2019 estimated O&M expenditures are $299k, capital expenditures are $4.4M.

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:
Final review of existing FGD Wastewater treatment (WWT) systems across the Duke Energy fleet consisting of physical/chemical and biological technologies, and after several comprehensive design reviews of vendor equipment and balance of plant components, DEF has developed preliminary estimated costs to operate and maintain the CR 4&5 FGD WWT system, which includes employee and contractor labor costs, wastewater treatment chemical costs and material handling and maintenance expenses. Project construction has begun and will continue through February 2019. DEF expects this project to be placed in-service by February 2019.

Project Fiscal Expenditures:
For 2018, 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 $34.1M. Capital expenditures for CAIR/CAMR Crystal River - Conditions of Certification (Project 7.4) are expected to be $45.0M.

Project Progress Summary:
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program. The FGD WWT project will comply with EPA's CCR rule, ELG requirements, and FDEP's Consent Order OCG Case No. 09-3463D, Third Amendment.

Project Projections:
2019 estimated O&M and capital expenditures are $35.8M and $3.9M respectively.

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 2018.

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 2019.

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, scheduled to be completed by first quarter 2019.
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 idenfitied (MWC-1, MWC-31 and MWC-32). This additional assesment 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:
2018 O&M expenditures are expected to be $170k.

Project Progress Summary:
DEF is evaluating monitoring data and other options to achieve compliance in accordance to Consent Order.

Project Projections:
2019 O&M expenditures are forecasted to be $150k.

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:
2018 Capital expenditures are estimated to be $600, O&M expenditures are also estimated to be $600. Sea turtle nesting season started May 1, 2018, and recently DEF was notified of possible street light issues in Clearwater, FL which may require amber lens installations and/or new lighting.

Project Progress Summary:
DEF is on schedule with activities identified for this program.

Project Projections:
2019 estimated O&M and Capital expenditures are $350 and $400 respectively.

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 2018 estimated expenditures for this project.

Project Progress Summary:
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

Project Projections:
No 2019 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 2018 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 2019 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 2018 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 2019 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 2018 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 2019 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 2018 estimated expenditures for this project.

Project Progress Summary:
The mercury TMDL study concluded in 2012.

Project Projections:
No 2019 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 2018 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA during 2010.

Project Projections:
No 2019 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 2018 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA in September 2010.

Project Projections:
No 2019 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:
For 2018, capital expenditures are expected to be $911k. O&M is expected to be $40k.

Project Progress Summary:
The first phase of the project will complete construction in 2018, which involves establishing a line from the Ash Sluice Pump Discharge to the FGD Filtrate tanks, and replace the old Sludge Return Pumps with dry seals.

Project Projections:
No 2019 capital or O&M expenditures are forecasted for 2019

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:
2018 O&M expenditures are estimated to be $32k. No capital expenditures are forecasted for 2018.

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:
2019 estimated O&M expenditures are $26k. No capital expenditures are expected in 2019.

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:
2018 O&M expenditures are estimated to be $459K.

Project Progress Summary:
Initial implementation of the CR4&5 MATS compliance plan is complete.

Project Projections:
2019 estimated O&M is $598k. No capital expenditures are forecasted in 2019.

Docket No. 20180007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
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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 2018 expenditures are expected for this project.

Project Progress Summary:
This project is in-service.

Project Projections:
No 2019 expenditures are expected for this project.

Project Title: **Mercury & Air Toxic Standards (MATS) CR1 & CR2**
Project No. 17.2

Project Description:
DEF is implementing 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:
2018 O&M expenditures are expected to be $1.5M.

Project Progress Summary:
Implementation of the CR1&2 MATS Compliance Plan is complete.

Project Projections:
2019 estimated O&M expenditures are $60k. No capital expenditures are expected in 2019.

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. Work started on dewatering and solids excavation for closure of the FGD Blowdown Ponds The groundwater assessment project for the FGD Blowdown Ponds and Ash Landfill continued per the requirements of the rule.

Project Fiscal Expenditures:
2018 estimated O&M and capital expenditures are $896k and $114k, respectively.

Project Progress Summary:
Ash Landfill: Ground water monitoring well installation, data gathering, and analysis is being performed. Groundwater assessment results has required additional groundwater sampling/analyses, corrective measures study, nature and extent delineation study, and alternative source demonstration.

FGD Blowdown Ponds: Work has started on dewatering and solids removal from the primary FGD Blowdown Pond. Development of a closure plan for the FGD Blowdown pond is underway. Groundwater assessment results have triggered detection monitoring and alternative source demonstration.

Vegetation Management & Inspection Work: More frequent mowing and inspection work is being performed, to comply with the CCR Rule.

Project Projections:
2019 estimated O&M expenditures are $4.1M, capital is forecasted to be $168k.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % by Rate Class
January 2019 - December 2019

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	20,593,148	4,291.48	0.370	0.9413447	21,876,309	4,558.88	21,876,309	6,749.0	52.591%	60.276%	64.928%	59.685%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.576	2,001,248	396.85	0.451	0.9413447	2,125,946	421.58	2,125,946	537.9	5.111%	5.574%	5.175%	5.538%
Primary	0.576	15,976	3.17	0.451	0.9719653	16,437	3.26	16,437	4.2	0.040%	0.043%	0.040%	0.043%
Transmission	0.576	2,484	0.49	0.451	0.9819653	2,530	0.50	0	0.0	0.006%	0.007%	0.000%	0.007%
										5.156%	5.624%	5.215%	5.588%
General Service													
GS-2 Secondary	1.000	177,263	20.24	1.000	0.9413447	188,308	21.50	188,308	21.5	0.453%	0.284%	0.207%	0.297%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.742	11,774,036	1,810.48	0.626	0.9413447	12,507,677	1,923.29	12,507,677	2,280.9	30.069%	25.429%	21.943%	25.786%
Primary	0.742	2,187,476	336.37	0.626	0.9719653	2,250,570	346.07	2,250,570	410.4	5.410%	4.576%	3.948%	4.640%
Secondary Del/ Primary Mtr	0.742	29,381	4.52	0.626	0.9719653	30,228	4.65	30,228	5.5	0.073%	0.061%	0.053%	0.062%
Transm Del/ Primary Mtr	0.742	0	0.00	0.626	0.9719653	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transmission	0.742	0	0.00	0.626	0.9819653	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	0.796	44,079	6.32	0.324	0.9719653	45,350	6.51	45,350	16.0	0.109%	0.086%	0.154%	0.088%
Transm Del/ Transm Mtr	0.796	8,533	1.22	0.324	0.9819653	8,690	1.25	0	0.0	0.021%	0.016%	0.000%	0.017%
Transm Del/ Primary Mtr	0.796	1,872	0.27	0.324	0.9719653	1,926	0.28	0	0.0	0.005%	0.004%	0.000%	0.004%
										35.686%	30.172%	26.099%	30.596%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	1.082	(0)	(0.00)	0.334	0.9413447	(0)	(0.00)	(0)	(0.0)	0.000%	0.000%	0.000%	0.000%
Primary	1.082	71,221	7.51	0.334	0.9719653	73,275	7.73	73,275	25.0	0.176%	0.102%	0.241%	0.108%
SS-3 Primary	1.248	66,505	6.08	0.380	0.9719653	68,423	6.26	68,423	20.6	0.164%	0.083%	0.198%	0.089%
										0.341%	0.185%	0.439%	0.197%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.911	89,356	11.19	0.707	0.9413447	94,924	11.89	94,924	15.3	0.228%	0.157%	0.147%	0.163%
Sec Del/Primary Mtr	0.911	4,978	0.62	0.707	0.9719653	5,122	0.64	5,122	0.8	0.012%	0.008%	0.008%	0.009%
Primary Del / Primary Mtr	0.911	1,113,149	139.45	0.707	0.9719653	1,145,256	143.47	1,145,256	184.9	2.753%	1.897%	1.779%	1.963%
Primary Del / Transm Mtr	0.911	249	0.03	0.707	0.9819653	254	0.03	254	0.0	0.001%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.911	346,705	43.43	0.707	0.9819653	353,073	44.23	0	0.0	0.849%	0.585%	0.000%	0.605%
Transm Del/ Primary Mtr	0.911	223,444	27.99	0.707	0.9719653	229,889	28.80	0	0.0	0.553%	0.381%	0.000%	0.394%
SS-2 Primary	0.686	60,525	10.07	0.272	0.9719653	62,271	10.37	62,271	26.1	0.150%	0.137%	0.251%	0.138%
Transm Del/ Transm Mtr	0.686	92,935	15.47	0.272	0.9819653	94,642	15.75	0	0.0	0.228%	0.208%	0.000%	0.210%
Transm Del/ Primary Mtr	0.686	11,069	1.84	0.272	0.9719653	11,388	1.90	0	0.0	0.027%	0.025%	0.000%	0.025%
										4.800%	3.399%	2.186%	3.507%
Lighting													
LS-1 (Secondary)	10.191	380,801	4.27	0.479	0.9413447	404,528	4.53	404,528	96.4	0.972%	0.060%	0.927%	0.130%
		39,296,432	7,139.36			41,597,015	7,563.34	40,894,878	10,394.7	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 2018 to December 2018
(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 2016
(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 2019 - December 2019

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	52.591%	60.276%	64.928%	59.685%	$28,353,223	$133,255	$22,570	$983,022	$29,492,071	20,593,148	**0.143**
General Service Non-Demand											
GS-1, GST-1											
Secondary										2,001,248	**0.143**
Primary										15,816	**0.142**
Transmission										2,434	**0.140**
TOTAL GS	5.156%	5.624%	5.215%	5.588%	$2,779,956	$12,432	$1,813	$92,031	$2,886,232	**2,019,498**	
General Service											
GS-2 Secondary	0.453%	0.284%	0.207%	0.297%	$244,061	$628	$71.89	$4,894.59	$249,655	177,263	**0.141**
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										11,774,036	**0.141**
Primary										2,240,180	**0.140**
Transmission										8,362	**0.138**
TOTAL GSD	35.686%	30.172%	26.099%	30.596%	$19,239,433	$66,703	$9,072	$503,930	$19,819,138	**14,022,578**	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										(0)	**0.137**
Primary										136,349	**0.136**
Transmission										-	**0.134**
TOTAL CS	0.341%	0.185%	0.439%	0.197%	$183,651	$409	$152	$3,244	$187,456	**136,349**	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										89,356	**0.138**
Primary										1,399,033	**0.137**
Transmission										431,091	**0.135**
TOTAL IS	4.800%	3.399%	2.186%	3.507%	$2,588,015	$7,514	$760	$57,758	$2,654,048	**1,919,481**	
Lighting											
LS-1 Secondary	0.972%	0.060%	0.927%	0.130%	$524,297	$132	$322.40	$2,142.95	$526,895	380,801	**0.138**
	100.000%	100.000%	100.000%	100.000%	$53,912,636	$221,074	$34,762	$1,647,022	$55,815,494	39,249,117	**0.142**

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 2019 to December 2019
(11) (Column 9 / Column 10)/10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Capital Structure and Cost Rates

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%	5.75%
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%	0.01%
Total	$	10,692,175,379	100.00%		6.38%	7.84%
				Total Debt	2.08%	2.08%
				Total Equity	4.30%	5.76%

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 WACC used for 2019 has been adjusted in compliance with paragraphs 16 and 19 of DEF's Settlement Agreement.

Project Title: **Mercury & Air Toxic Standards (MATS) CR1 & CR2**
Project No. 17.2

Project Description:
DEF is implementing 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:
2018 O&M expenditures are expected to be $1.5M.

Project Progress Summary:
Implementation of the CR1&2 MATS Compliance Plan is complete.

Project Projections:
2019 estimated O&M expenditures are $60k. No capital expenditures are expected in 2019.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % by Rate Class
January 2019 - December 2019

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	20,593,148	4,291.48	0.370	0.9413447	21,876,309	4,558.88	21,876,309	6,749.0	52.591%	60.276%	64.928%	59.685%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.576	2,001,248	396.85	0.451	0.9413447	2,125,946	421.58	2,125,946	537.9	5.111%	5.574%	5.175%	5.538%
Primary	0.576	15,976	3.17	0.451	0.9719653	16,437	3.26	16,437	4.2	0.040%	0.043%	0.040%	0.043%
Transmission	0.576	2,484	0.49	0.451	0.9819653	2,530	0.50	0	0.0	0.006%	0.007%	0.000%	0.007%
										5.156%	5.624%	5.215%	5.588%
General Service													
GS-2 Secondary	1.000	177,263	20.24	1.000	0.9413447	188,308	21.50	188,308	21.5	0.453%	0.284%	0.207%	0.297%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.742	11,774,036	1,810.48	0.626	0.9413447	12,507,677	1,923.29	12,507,677	2,280.9	30.069%	25.429%	21.943%	25.786%
Primary	0.742	2,187,476	336.37	0.626	0.9719653	2,250,570	346.07	2,250,570	410.4	5.410%	4.576%	3.948%	4.640%
Secondary Del/ Primary Mtr	0.742	29,381	4.52	0.626	0.9719653	30,228	4.65	30,228	5.5	0.073%	0.061%	0.053%	0.062%
Transm Del/ Primary Mtr	0.742	0	0.00	0.626	0.9719653	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transmission	0.742	0	0.00	0.626	0.9819653	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	0.796	44,079	6.32	0.324	0.9719653	45,350	6.51	45,350	16.0	0.109%	0.086%	0.154%	0.088%
Transm Del/ Transm Mtr	0.796	8,533	1.22	0.324	0.9819653	8,690	1.25	0	0.0	0.021%	0.016%	0.000%	0.017%
Transm Del/ Primary Mtr	0.796	1,872	0.27	0.324	0.9719653	1,926	0.28	0	0.0	0.005%	0.004%	0.000%	0.004%
										35.686%	30.172%	26.099%	30.596%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	1.082	(0)	(0.00)	0.334	0.9413447	(0)	(0.00)	(0)	(0.0)	0.000%	0.000%	0.000%	0.000%
Primary	1.082	71,221	7.51	0.334	0.9719653	73,275	7.73	73,275	25.0	0.176%	0.102%	0.241%	0.108%
SS-3 Primary	1.248	66,505	6.08	0.380	0.9719653	68,423	6.26	68,423	20.6	0.164%	0.083%	0.198%	0.089%
										0.341%	0.185%	0.439%	0.197%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.911	89,356	11.19	0.707	0.9413447	94,924	11.89	94,924	15.3	0.228%	0.157%	0.147%	0.163%
Sec Del/Primary Mtr	0.911	4,978	0.62	0.707	0.9719653	5,122	0.64	5,122	0.8	0.012%	0.008%	0.008%	0.009%
Primary Del / Primary Mtr	0.911	1,113,149	139.45	0.707	0.9719653	1,145,256	143.47	1,145,256	184.9	2.753%	1.897%	1.779%	1.963%
Primary Del / Transm Mtr	0.911	249	0.03	0.707	0.9819653	254	0.03	254	0.0	0.001%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.911	346,705	43.43	0.707	0.9819653	353,073	44.23	0	0.0	0.849%	0.585%	0.000%	0.605%
Transm Del/ Primary Mtr	0.911	223,444	27.99	0.707	0.9719653	229,889	28.80	0	0.0	0.553%	0.381%	0.000%	0.394%
SS-2 Primary	0.686	60,525	10.07	0.272	0.9719653	62,271	10.37	62,271	26.1	0.150%	0.137%	0.251%	0.138%
Transm Del/ Transm Mtr	0.686	92,935	15.47	0.272	0.9819653	94,642	15.75	0	0.0	0.228%	0.208%	0.000%	0.210%
Transm Del/ Primary Mtr	0.686	11,069	1.84	0.272	0.9719653	11,388	1.90	0	0.0	0.027%	0.025%	0.000%	0.025%
										4.800%	3.399%	2.186%	3.507%
Lighting													
LS-1 (Secondary)	10.191	380,801	4.27	0.479	0.9413447	404,528	4.53	404,528	96.4	0.972%	0.060%	0.927%	0.130%
		39,296,432	7,139.36			41,597,015	7,563.34	40,894,878	10,394.7	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 2018 to December 2018
(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 2016
(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 2019 - December 2019

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	52.591%	60.276%	64.928%	59.685%	$28,353,223	$133,255	$22,570	$983,022	$29,492,071	20,593,148	**0.143**
General Service Non-Demand											
GS-1, GST-1											
Secondary										2,001,248	**0.143**
Primary										15,816	**0.142**
Transmission										2,434	**0.140**
TOTAL GS	5.156%	5.624%	5.215%	5.588%	$2,779,956	$12,432	$1,813	$92,031	$2,886,232	**2,019,498**	
General Service											
GS-2 Secondary	0.453%	0.284%	0.207%	0.297%	$244,061	$628	$71.89	$4,894.59	$249,655	177,263	**0.141**
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										11,774,036	**0.141**
Primary										2,240,180	**0.140**
Transmission										8,362	**0.138**
TOTAL GSD	35.686%	30.172%	26.099%	30.596%	$19,239,433	$66,703	$9,072	$503,930	$19,819,138	**14,022,578**	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										(0)	**0.137**
Primary										136,349	**0.136**
Transmission										-	**0.134**
TOTAL CS	0.341%	0.185%	0.439%	0.197%	$183,651	$409	$152	$3,244	$187,456	**136,349**	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										89,356	**0.138**
Primary										1,399,033	**0.137**
Transmission										431,091	**0.135**
TOTAL IS	4.800%	3.399%	2.186%	3.507%	$2,588,015	$7,514	$760	$57,758	$2,654,048	**1,919,481**	
Lighting											
LS-1 Secondary	0.972%	0.060%	0.927%	0.130%	$524,297	$132	$322.40	$2,142.95	$526,895	380,801	**0.138**
	100.000%	100.000%	100.000%	100.000%	$53,912,636	$221,074	$34,762	$1,647,022	$55,815,494	39,249,117	**0.142**

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 2019 to December 2019
(11) (Column 9 / Column 10)/10

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Calculation of Projection Amount
January 2019 - December 2019

Capital Structure and Cost Rates

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%	5.75%
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%	0.01%
Total	$	10,692,175,379	100.00%		6.38%	7.84%
				Total Debt	2.08%	2.08%
				Total Equity	4.30%	5.76%

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 WACC used for 2019 has been adjusted in compliance with paragraphs 16 and 19 of DEF's Settlement Agreement.

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Capital Program Detail

January 2019 - December 2019
Calculation of Projected Period Amount

Docket No. 20180007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 20
PARTY: DUKE ENERGY FLORIDA, INC. (DEF)(DIRECT)
DESCRIPTION: Christopher Menendez CAM-6

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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	4,555	3,645	2,734	1,824	914	(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	$5,465	$4,555	$3,645	$2,735	$1,825	$915	$0	$0	$0	$0	$0	
6	Average Net Investment				6,830	5,920	5,010	4,100	3,190	2,280	1,370	457	0	0	0	0	
7	Return on Average Net Investment (A)																
	a. Debt Component		2.08%		12	10	9	7	6	4	2	1	0	0	0	0	51
	b. Equity Component Grossed Up For Taxes		5.76%		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	915	0	0	0	0	7,285
	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	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	$918	$0	$0	$0	$0	$7,476
	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	$918	$0	$0	$0	$0	$7,476

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)																
	a. Debt Component		2.08%		339	294	249	204	158	113	68	23	0	0	0	0	1,448
	b. Equity Component Grossed Up For Taxes		5.76%		939	813	688	563	438	313	188	63	0	0	0	0	4,005
	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	$27,180	$27,010	$26,840	$26,669	$26,499	$26,329	$26,159	$0	$0	$0	$0	$214,039
	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	$27,180	$27,010	$26,840	$26,669	$26,499	$26,329	$26,159	$0	$0	$0	$0	$214,039

(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.

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)																
	a. Debt Component		2.08%		259	224	190	155	121	86	52	17	0	0	0	0	1,104
	b. Equity Component Grossed Up For Taxes		5.76%		715	620	525	429	334	238	143	48	0	0	0	0	3,052
	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	$20,719	$20,590	$20,459	$20,330	$20,199	$20,070	$19,940	$0	$0	$0	$0	$163,157
	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				$20,849	$20,719	$20,590	$20,459	$20,330	$20,199	$20,070	$19,940	$0	$0	$0	$0	$163,157

For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)																
	a. Debt Component		2.08%		41	36	30	25	19	14	8	3	0	0	0	0	176
	b. Equity Component Grossed Up For Taxes		5.76%		114	99	83	68	53	38	23	8	0	0	0	0	486
	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	$3,294	$3,272	$3,252	$3,231	$3,211	$3,190	$3,170	$0	$0	$0	$0	$25,932
	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	$3,294	$3,272	$3,252	$3,231	$3,211	$3,190	$3,170	$0	$0	$0	$0	$25,932

(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	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)																
	a. Debt Component		2.08%		198	119	40	0	0	0	0	0	0	0	0	0	357
	b. Equity Component Grossed Up For Taxes		5.76%		549	329	110	0	0	0	0	0	0	0	0	0	988
	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)				$46,454	$46,155	$45,868	$0	$0	$0	$0	$0	$0	$0	$0	$0	$138,477
	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				$46,454	$46,155	$45,868	$0	$0	$0	$0	$0	$0	$0	$0	$0	$138,477

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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			(425,175)	(428,860)	(432,545)	(436,230)	(439,915)	(443,600)	(447,285)	(450,970)	(454,655)	(458,340)	(462,025)	(465,710)	(469,395)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$1,048,626	$1,044,941	$1,041,256	$1,037,571	$1,033,886	$1,030,201	$1,026,516	$1,022,831	$1,019,146	$1,015,461	$1,011,776	$1,008,091	$1,004,406	
6	Average Net Investment				1,046,783	1,043,098	1,039,413	1,035,728	1,032,043	1,028,358	1,024,673	1,020,988	1,017,303	1,013,618	1,009,933	1,006,248	
7	Return on Average Net Investment (A)																
	a. Debt Component		2.08%		1,817	1,811	1,804	1,798	1,791	1,785	1,779	1,772	1,766	1,759	1,753	1,747	21,382
	b. Equity Component Grossed Up For Taxes		5.76%		5,024	5,007	4,989	4,971	4,954	4,936	4,918	4,901	4,883	4,865	4,848	4,830	59,126
	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	0.009930			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)				$11,746	$11,723	$11,698	$11,674	$11,650	$11,626	$11,602	$11,578	$11,554	$11,529	$11,506	$11,482	$139,368
	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				$11,746	$11,723	$11,698	$11,674	$11,650	$11,626	$11,602	$11,578	$11,554	$11,529	$11,506	$11,482	$139,368

(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	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		857	842	826	810	794	778	762	746	731	715	699	683	9,243
	b. Equity Component Grossed Up For Taxes	5.76%		2,371	2,327	2,283	2,239	2,195	2,152	2,108	2,064	2,020	1,976	1,932	1,888	25,555
	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)			$13,544	$13,485	$13,425	$13,365	$13,305	$13,246	$13,186	$13,126	$13,067	$13,007	$12,947	$12,887	$158,590
	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			$13,544	$13,485	$13,425	$13,365	$13,305	$13,246	$13,186	$13,126	$13,067	$13,007	$12,947	$12,887	$158,590

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		139	138	137	135	134	133	132	130	129	128	127	125	1,587
	b. Equity Component Grossed Up For Taxes	5.76%		384	381	378	374	371	367	364	360	357	353	350	347	4,386
	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)			$1,379	$1,375	$1,371	$1,365	$1,361	$1,356	$1,352	$1,346	$1,342	$1,337	$1,333	$1,328	$16,245
	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			$1,379	$1,375	$1,371	$1,365	$1,361	$1,356	$1,352	$1,346	$1,342	$1,337	$1,333	$1,328	$16,245

(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	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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		(242,480)	(244,302)	(246,124)	(247,946)	(249,768)	(251,590)	(253,412)	(255,234)	(257,056)	(258,878)	(260,700)	(262,522)	(264,344)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$487,815	$485,993	$484,171	$482,349	$480,527	$478,705	$476,883	$475,061	$473,239	$471,417	$469,595	$467,773	$465,951	
6	Average Net Investment			486,904	485,082	483,260	481,438	479,616	477,794	475,972	474,150	472,328	470,506	468,684	466,862	
7	Return on Average Net Investment (A)															
	a. Debt Component	2.08%		845	842	839	836	833	829	826	823	820	817	814	810	9,934
	b. Equity Component Grossed Up For Taxes	5.76%		2,337	2,328	2,320	2,311	2,302	2,293	2,285	2,276	2,267	2,258	2,250	2,241	27,468
	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	0.009930		604	604	604	604	604	604	604	604	604	604	604	604	7,248
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			$5,608	$5,596	$5,585	$5,573	$5,561	$5,548	$5,537	$5,525	$5,513	$5,501	$5,490	$5,477	$66,514
	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			$5,608	$5,596	$5,585	$5,573	$5,561	$5,548	$5,537	$5,525	$5,513	$5,501	$5,490	$5,477	$66,514

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		1,117	1,112	1,107	1,102	1,097	1,092	1,087	1,082	1,077	1,072	1,067	1,062	13,074
	b. Equity Component Grossed Up For Taxes	5.76%		3,088	3,075	3,061	3,047	3,033	3,020	3,006	2,992	2,979	2,965	2,951	2,938	36,155
	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)			$7,806	$7,788	$7,769	$7,750	$7,731	$7,713	$7,694	$7,675	$7,657	$7,638	$7,619	$7,601	$92,441
	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			$7,806	$7,788	$7,769	$7,750	$7,731	$7,713	$7,694	$7,675	$7,657	$7,638	$7,619	$7,601	$92,441

(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	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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			(822,074)	(829,911)	(837,748)	(845,585)	(853,422)	(861,259)	(869,096)	(876,933)	(884,770)	(892,607)	(900,444)	(908,281)	(916,118)	
4	CWIP - Non-Interest Bearing			0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)			$2,794,830	$2,786,993	$2,779,156	$2,771,319	$2,763,482	$2,755,645	$2,747,808	$2,739,971	$2,732,134	$2,724,297	$2,716,460	$2,708,623	$2,700,786	
6	Average Net Investment				2,790,911	2,783,074	2,775,237	2,767,400	2,759,563	2,751,726	2,743,889	2,736,052	2,728,215	2,720,378	2,712,541	2,704,704	
7	Return on Average Net Investment (A)																
	a. Debt Component		2.08%		4,845	4,831	4,817	4,804	4,790	4,777	4,763	4,749	4,736	4,722	4,709	4,695	57,238
	b. Equity Component Grossed Up For Taxes		5.76%		13,396	13,358	13,321	13,283	13,246	13,208	13,170	13,133	13,095	13,057	13,020	12,982	158,269
	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	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)				$29,583	$29,531	$29,480	$29,429	$29,378	$29,327	$29,275	$29,224	$29,173	$29,121	$29,071	$29,019	$351,611
	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				$29,583	$29,531	$29,480	$29,429	$29,378	$29,327	$29,275	$29,224	$29,173	$29,121	$29,071	$29,019	$351,611

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)			$78,200	$77,959	$77,718	$77,477	$77,236	$76,995	$76,754	$76,513	$76,272	$76,031	$75,790	$75,549	$75,308	
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)																
	a. Debt Component		2.08%		136	135	135	134	134	133	133	133	132	132	131	131	1,599
	b. Equity Component Grossed Up For Taxes		5.76%		375	374	372	371	370	369	368	367	366	364	363	362	4,421
	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)				$906	$904	$902	$900	$899	$897	$896	$895	$893	$891	$889	$888	$10,760
	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				$906	$904	$902	$900	$899	$897	$896	$895	$893	$891	$889	$888	$10,760

(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	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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		$394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	
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)	(225,036)	
4	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)															
	a. Debt Component	2.08%		330	327	324	321	318	315	312	309	306	303	300	297	3,762
	b. Equity Component Grossed Up For Taxes	5.76%		914	905	897	888	880	871	863	854	845	837	828	820	10,402
	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			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)			$3,348	$3,336	$3,325	$3,313	$3,302	$3,290	$3,279	$3,267	$3,255	$3,244	$3,232	$3,221	$39,412
	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			$3,348	$3,336	$3,325	$3,313	$3,302	$3,290	$3,279	$3,267	$3,255	$3,244	$3,232	$3,221	$39,412

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		23	23	23	23	23	23	22	22	22	22	22	21	269
	b. Equity Component Grossed Up For Taxes	5.76%		65	64	64	63	63	62	62	61	61	60	60	59	744
	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)			$195	$194	$194	$193	$193	$192	$191	$190	$190	$189	$189	$187	$2,297
	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			$195	$194	$194	$193	$193	$192	$191	$190	$190	$189	$189	$187	$2,297

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-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-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)																
	a. Debt Component		2.08%		4,122	4,117	4,112	4,107	4,102	4,097	4,092	4,087	4,082	4,077	4,072	4,066	49,133
	b. Equity Component Grossed Up For Taxes		5.76%		11,399	11,385	11,371	11,357	11,343	11,329	11,315	11,301	11,287	11,273	11,259	11,244	135,863
	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)				$18,775	$18,756	$18,737	$18,718	$18,699	$18,680	$18,661	$18,642	$18,623	$18,604	$18,585	$18,564	$224,044
	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				$18,775	$18,756	$18,737	$18,718	$18,699	$18,680	$18,661	$18,642	$18,623	$18,604	$18,585	$18,564	$224,044

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)			$211,212	$210,687	$210,162	$209,637	$209,112	$208,587	$208,062	$207,537	$207,012	$206,487	$205,962	$205,437	$204,912	
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)																
	a. Debt Component		2.08%		366	365	364	363	363	362	361	360	359	358	357	356	4,334
	b. Equity Component Grossed Up For Taxes		5.76%		1,013	1,010	1,007	1,005	1,002	1,000	997	995	992	990	987	985	11,983
	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)				$2,109	$2,105	$2,101	$2,098	$2,095	$2,092	$2,088	$2,085	$2,081	$2,078	$2,074	$2,071	$25,077
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$2,109	$2,105	$2,101	$2,098	$2,095	$2,092	$2,088	$2,085	$2,081	$2,078	$2,074	$2,071	$25,077

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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		$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	
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)															
	a. Debt Component	2.08%		197	196	195	195	194	193	193	192	191	190	190	189	2,315
	b. Equity Component Grossed Up For Taxes	5.76%		544	542	540	538	536	534	533	531	529	527	525	523	6,402
	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)			$1,272	$1,269	$1,266	$1,264	$1,261	$1,258	$1,257	$1,254	$1,251	$1,248	$1,246	$1,243	$15,089
	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			$1,272	$1,269	$1,266	$1,264	$1,261	$1,258	$1,257	$1,254	$1,251	$1,248	$1,246	$1,243	$15,089

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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		$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	
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)															
	a. Debt Component	2.08%		377	376	375	375	374	374	373	372	372	371	370	370	4,479
	b. Equity Component Grossed Up For Taxes	5.76%		1,042	1,040	1,038	1,036	1,035	1,033	1,031	1,030	1,028	1,026	1,024	1,023	12,386
	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)			$2,005	$2,002	$1,999	$1,997	$1,995	$1,993	$1,990	$1,988	$1,986	$1,983	$1,980	$1,979	$23,897
	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			$2,005	$2,002	$1,999	$1,997	$1,995	$1,993	$1,990	$1,988	$1,986	$1,983	$1,980	$1,979	$23,897

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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			$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	
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)																
	a. Debt Component		2.08%		254	253	253	252	251	251	250	249	249	248	247	247	3,004
	b. Equity Component Grossed Up For Taxes		5.76%		702	700	699	697	695	693	691	689	688	686	684	682	8,306
	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)				$1,505	$1,502	$1,501	$1,498	$1,495	$1,493	$1,490	$1,487	$1,486	$1,483	$1,480	$1,478	$17,898
	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				$1,505	$1,502	$1,501	$1,498	$1,495	$1,493	$1,490	$1,487	$1,486	$1,483	$1,480	$1,478	$17,898

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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			$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	
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)																
	a. Debt Component		2.08%		100	99	99	99	98	98	98	97	97	96	96	96	1,173
	b. Equity Component Grossed Up For Taxes		5.76%		276	275	274	273	272	271	270	269	268	267	266	265	3,246
	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)				$680	$678	$677	$676	$674	$673	$672	$670	$669	$667	$666	$665	$8,067
	a. Recoverable Costs Allocated to Energy				0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand				$680	$678	$677	$676	$674	$673	$672	$670	$669	$667	$666	$665	$8,067

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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			$347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	
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)	(107,313)	
4	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)																
	a. Debt Component		2.08%		433	432	430	429	427	426	424	423	421	420	419	417	5,101
	b. Equity Component Grossed Up For Taxes		5.76%		1,198	1,194	1,190	1,186	1,182	1,178	1,174	1,170	1,166	1,161	1,157	1,153	14,109
	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)				$2,757	$2,752	$2,746	$2,741	$2,735	$2,730	$2,724	$2,719	$2,713	$2,707	$2,702	$2,696	$32,722
	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				$2,757	$2,752	$2,746	$2,741	$2,735	$2,730	$2,724	$2,719	$2,713	$2,707	$2,702	$2,696	$32,722

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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			$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)																
	a. Debt Component		2.08%		425	423	422	421	419	418	417	415	414	413	411	410	5,008
	b. Equity Component Grossed Up For Taxes		5.76%		1,175	1,171	1,167	1,163	1,160	1,156	1,152	1,148	1,144	1,141	1,137	1,133	13,847
	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)				$2,635	$2,629	$2,624	$2,619	$2,614	$2,609	$2,604	$2,598	$2,593	$2,589	$2,583	$2,578	$31,275
	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				$2,635	$2,629	$2,624	$2,619	$2,614	$2,609	$2,604	$2,598	$2,593	$2,589	$2,583	$2,578	$31,275

(A) The allowable return is per the methodology approved in Order No. PSC-2012-0425-PAA-EU.

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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	6,449	3,224	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	$6,449	$3,224	$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)															
	a. Debt Component	2.08%		14	8	3	0	0	0	0	0	0	0	0	0	25
	b. Equity Component Grossed Up For Taxes	5.76%		39	23	8	0	0	0	0	0	0	0	0	0	70
	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	3,224	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)			$3,278	$3,256	$3,235	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,769
	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			$3,278	$3,256	$3,235	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,769

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description		Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)															
	a. Debt Component	2.08%		556	555	554	553	553	552	551	550	550	549	548	548	6,619
	b. Equity Component Grossed Up For Taxes	5.76%		1,536	1,534	1,532	1,530	1,528	1,526	1,524	1,522	1,520	1,518	1,516	1,514	18,300
	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)			$2,771	$2,768	$2,765	$2,762	$2,760	$2,757	$2,754	$2,751	$2,749	$2,746	$2,743	$2,741	$33,067
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$2,771	$2,768	$2,765	$2,762	$2,760	$2,757	$2,754	$2,751	$2,749	$2,746	$2,743	$2,741	$33,067

(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: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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 (B)			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)																
	a. Debt Component		2.08%		3,410	3,403	3,395	3,387	3,380	3,372	3,364	3,357	3,349	3,341	3,334	3,326	40,418
	b. Equity Component Grossed Up For Taxes		5.76%		9,431	9,409	9,388	9,367	9,346	9,324	9,303	9,282	9,261	9,239	9,218	9,197	111,765
	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)				$17,570	$17,541	$17,512	$17,483	$17,455	$17,425	$17,396	$17,368	$17,339	$17,309	$17,281	$17,252	$208,931
	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				$17,570	$17,541	$17,512	$17,483	$17,455	$17,425	$17,396	$17,368	$17,339	$17,309	$17,281	$17,252	$208,931

For Project: Crystal River 4 and 5 - Conditions of Certification (Project 7.4q)
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated Dec-19	End of Period Total
1	Investments																
	a. Expenditures/Additions				$834,226	$868,932	$859,616	$568,540	$355,994	$350,116	$66,587	$0	$0	$0	$0	$0	$3,904,011
	b. Clearings to Plant				0	0	77,833,623	568,540	355,994	350,116	66,587	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			$614,010	614,010	614,010	78,447,633	79,016,173	79,372,167	79,722,283	79,788,870	79,788,870	79,788,870	79,788,870	79,788,870	79,788,870	
3	Less: Accumulated Depreciation			(43,163)	(43,923)	(44,683)	(141,827)	(239,675)	(337,964)	(436,687)	(535,492)	(634,297)	(733,102)	(831,907)	(930,712)	(1,029,517)	
4	CWIP - Non-Interest Bearing (B)			75,270,849	76,105,075	76,974,007	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)			$75,841,696	$76,675,162	$77,543,334	$78,305,805	$78,776,497	$79,034,203	$79,285,596	$79,253,378	$79,154,573	$79,055,768	$78,956,963	$78,858,158	$78,759,353	
6	Average Net Investment				76,258,429	77,109,248	77,924,570	78,541,151	78,905,350	79,159,899	79,269,487	79,203,975	79,105,170	79,006,365	78,907,560	78,808,755	
7	Return on Average Net Investment (A)																
	a. Debt Component		2.08%		132,372	133,849	135,264	136,334	136,967	137,408	137,599	137,485	137,313	137,142	136,970	136,799	1,635,502
	b. Equity Component Grossed Up For Taxes		5.76%		366,030	370,113	374,027	376,986	378,734	379,956	380,482	380,168	379,694	379,219	378,745	378,271	4,522,425
	c. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses																
	a. Depreciation	1.4860%			760	760	97,144	97,848	98,289	98,723	98,805	98,805	98,805	98,805	98,805	98,805	986,354
	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	87	11,132	11,213	11,264	11,313	11,323	11,323	11,323	11,323	11,323	11,323	113,034
	e. Other				0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)				$499,249	$504,809	$617,567	$622,381	$625,254	$627,400	$628,209	$627,781	$627,135	$626,489	$625,843	$625,198	$7,257,315
	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				$499,249	$504,809	$617,567	$622,381	$625,254	$627,400	$628,209	$627,781	$627,135	$626,489	$625,843	$625,198	$7,257,315

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.

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4r) - CR4 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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)																
	a. Debt Component		2.08%		994	991	989	987	984	982	980	977	975	972	970	968	11,769
	b. Equity Component Grossed Up For Taxes		5.76%		2,748	2,741	2,735	2,728	2,722	2,715	2,708	2,702	2,695	2,689	2,682	2,676	32,541
	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)				$5,197	$5,187	$5,179	$5,170	$5,161	$5,152	$5,143	$5,134	$5,125	$5,116	$5,107	$5,099	$61,770
	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				$5,197	$5,187	$5,179	$5,170	$5,161	$5,152	$5,143	$5,134	$5,125	$5,116	$5,107	$5,099	$61,770

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4s) - CR5 Clinker Mitigation
(in Dollars)

Line	Description			Beginning of Period Amount	Estimated Jan-19	Estimated Feb-19	Estimated Mar-19	Estimated Apr-19	Estimated May-19	Estimated Jun-19	Estimated Jul-19	Estimated Aug-19	Estimated Sep-19	Estimated Oct-19	Estimated Nov-19	Estimated 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			$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																
	a. Debt Component		2.08%		783	781	779	778	776	774	772	770	768	767	765	763	9,276
	b. Equity Component Grossed Up For Taxes		5.76%		2,165	2,160	2,155	2,150	2,145	2,140	2,135	2,130	2,125	2,120	2,115	2,110	25,650
	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)				$4,061	$4,054	$4,047	$4,041	$4,034	$4,027	$4,020	$4,013	$4,006	$4,000	$3,993	$3,986	$48,282
	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				$4,061	$4,054	$4,047	$4,041	$4,034	$4,027	$4,020	$4,013	$4,006	$4,000	$3,993	$3,986	$48,282

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.

Docket No. 20180007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
Page 45 of 48

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. Work started on dewatering and solids excavation for closure of the FGD Blowdown Ponds The groundwater assessment project for the FGD Blowdown Ponds and Ash Landfill continued per the requirements of the rule.

Project Fiscal Expenditures:
2018 estimated O&M and capital expenditures are $896k and $114k, respectively.

Project Progress Summary:
Ash Landfill: Ground water monitoring well installation, data gathering, and analysis is being performed. Groundwater assessment results has required additional groundwater sampling/analyses, corrective measures study, nature and extent delineation study, and alternative source demonstration.

FGD Blowdown Ponds: Work has started on dewatering and solids removal from the primary FGD Blowdown Pond. Development of a closure plan for the FGD Blowdown pond is underway. Groundwater assessment results have triggered detection monitoring and alternative source demonstration.

Vegetation Management & Inspection Work: More frequent mowing and inspection work is being performed, to comply with the CCR Rule.

Project Projections:
2019 estimated O&M expenditures are $4.1M, capital is forecast

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 21
PARTY: DUKE ENERGY FLORIDA, INC. (DEF)(DIRECT)
DESCRIPTION: Timothy Hill CAM-5

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. Work started on dewatering and solids excavation for closure of the FGD Blowdown Ponds The groundwater assessment project for the FGD Blowdown Ponds and Ash Landfill continued per the requirements of the rule.

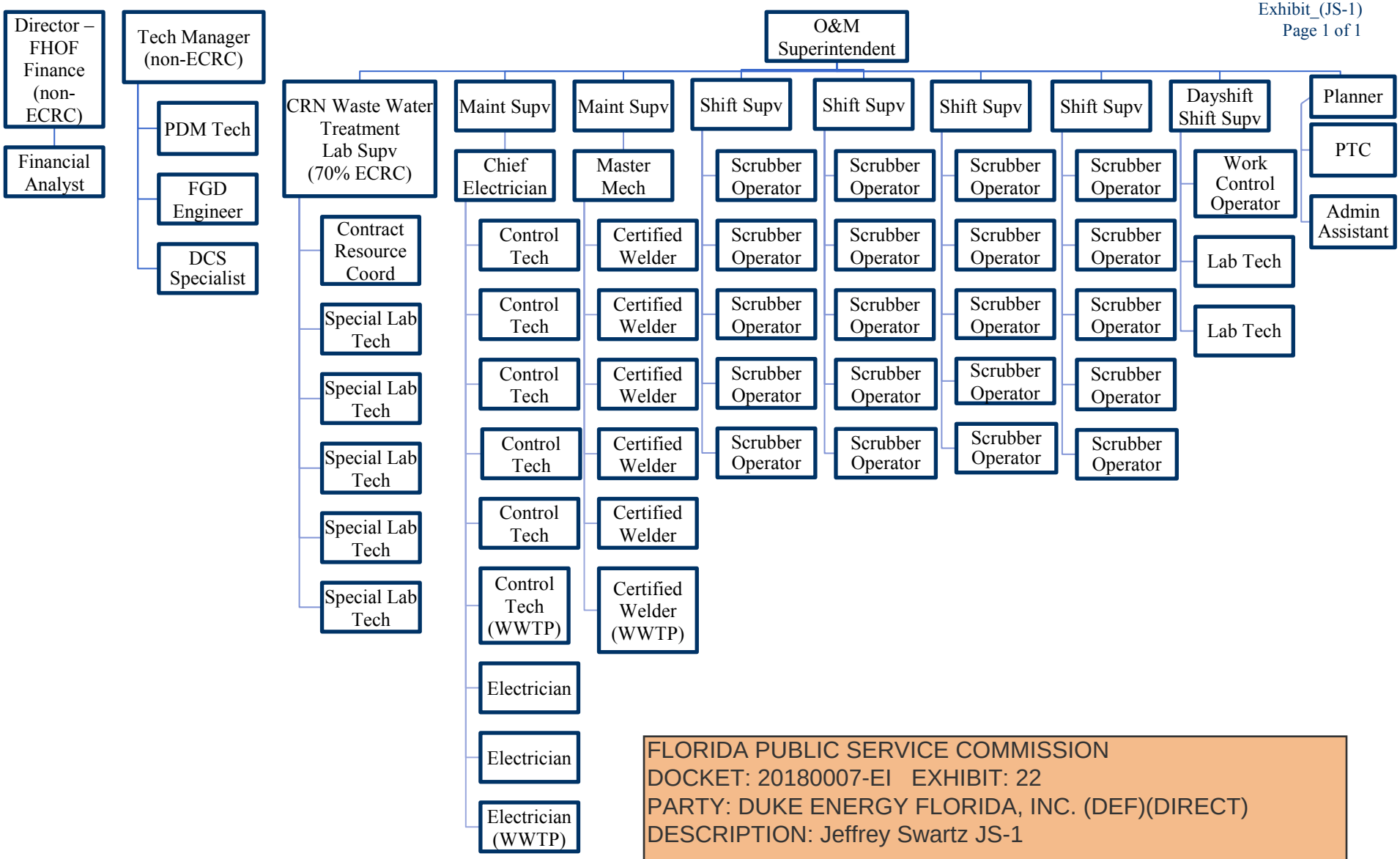
Project Fiscal Expenditures:
2018 estimated O&M and capital expenditures are $896k and $114k, respectively.

Project Progress Summary:
Ash Landfill: Ground water monitoring well installation, data gathering, and analysis is being performed. Groundwater assessment results has required additional groundwater sampling/analyses, corrective measures study, nature and extent delineation study, and alternative source demonstration.

FGD Blowdown Ponds: Work has started on dewatering and solids removal from the primary FGD Blowdown Pond. Development of a closure plan for the FGD Blowdown pond is underway. Groundwater assessment results have triggered detection monitoring and alternative source demonstration.

Vegetation Management & Inspection Work: More frequent mowing and inspection work is being performed, to comply with the CCR Rule.

Project Projections:
2019 estimated O&M expenditures are $4.1M, capital is forecasted to be $168k.



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 22
PARTY: DUKE ENERGY FLORIDA, INC. (DEF)(DIRECT)
DESCRIPTION: Jeffrey Swartz JS-1

DUKE ENERGY FLORIDA, LLC
Environmental Cost Recovery Clause
Commission Forms 42-1P Through 42-8P

January 2019 - December 2019
Calculation of Projected Period Amount

Docket No. 20180007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 23
PARTY: DUKE ENERGY FLORIDA, INC. (DEF)(DIRECT)
DESCRIPTION: Jeffrey Swartz CAM-5

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:
Final review of existing FGD Wastewater treatment (WWT) systems across the Duke Energy fleet consisting of physical/chemical and biological technologies, and after several comprehensive design reviews of vendor equipment and balance of plant components, DEF has developed preliminary estimated costs to operate and maintain the CR 4&5 FGD WWT system, which includes employee and contractor labor costs, wastewater treatment chemical costs and material handling and maintenance expenses. Project construction has begun and will continue through February 2019. DEF expects this project to be placed in-service by February 2019.

Project Fiscal Expenditures:
For 2018, 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 $34.1M. Capital expenditures for CAIR/CAMR Crystal River - Conditions of Certification (Project 7.4) are expected to be $45.0M.

Project Progress Summary:
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program. The FGD WWT project will comply with EPA's CCR rule, ELG requirements, and FDEP's Consent Order OCG Case No. 09-3463D, Third Amendment.

Project Projections:
2019 estimated O&M and capital expenditures are $35.8M and $3.9M respectively.

Docket No. 20180007-EI
Duke Energy Florida, LLC
Witness: C. A. Menendez
Exh. No. __ (CAM-5)
Page 43 of 48

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 2018 expenditures are expected for this project.

Project Progress Summary:
This project is in-service.

Project Projections:
No 2019 expenditures are expected for this project.

Project Title: **Mercury & Air Toxic Standards (MATS) CR1 & CR2**
Project No. 17.2

Project Description:
DEF is implementing 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:
2018 O&M expenditures are expected to be $1.5M.

Project Progress Summary:
Implementation of the CR1&2 MATS Compliance Plan is complete.

Project Projections:
2019 estimated O&M expenditures are $60k. No capital expenditures are expected in 2019.

Duke Energy Florida, LLC

Review of Integrated Clean Air Compliance Plan

Submitted to the
Florida Public Service Commission

April 2, 2018

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 24
PARTY: DUKE ENERGY FLORIDA, INC.
(DEF)(DIRECT)
DESCRIPTION: Patricia Q. West PQW-1



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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

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 2018.

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.

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 under the new Administration.

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 2018.

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; however, EPA stated that it will perform additional modeling that could result in changing that proposal.

On September 7, 2016, EPA finalized its CSAPR Update rule, lowering the current CSAPR state ozone season NO_x emission budgets for 22 Eastern states. EPA 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 must 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.

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 have been no 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."

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.

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.

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 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).

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 will allow 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 are operational. 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 intends to continue operating CR Units 1 and 2 in compliance with BART and MATS requirements as outlined in Order No. PSC-2014-0173-PAA-EI.

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 2018 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.

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:
As of the end of second quarter 2018, a total of 272 substation remediations are completed out of 279 slated for clean-up.

Project Fiscal Expenditures:
2018 O&M expenditures for the substation system program are estimated to be $856k, which is $174k or 25% higher than originally projected. The variance is primarily due to higher than anticipated remediation costs at Central Florida Substation than initially projected, and remediation work at the Kenneth City Substation coming in higher than originally estimated due to more contaminated soil excavated once the breaker/control house was removed.

Project Progress Summary:
DEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan (SARAP).

Project Projections:
2019 O&M estimated expenditures are $409k.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 25
PARTY: DUKE ENERGY FLORIDA, INC. (DEF)(DIRECT)
DESCRIPTION: Patricia Q. West CAM-5

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. Groundwater monitoring is in process.

Project Fiscal Expenditures:
There is $8K forecasted for 2018.

Project Progress Summary:
This project is complete with the exception of the groundwater monitoring at the 7100 Sunset Way, St. Petersburg Beach location.

Project Projections:
2019 O&M expenditures are expected to be $8k.

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 will be amortized over 26 months, and all four parts of this project will be fully amortized as of September 2019.

Project Fiscal Expenditures:
No capital or O&M expenditures are estimated for 2018.

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 will be fully amortized as of September 2019.

Project Projections:
No capital or O&M expenditures are estimated for 2019.

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 2018.

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. Consistent with DEF's petition filed August 4, 2016, DEF is treating the unrecovered investments as a regulatory asset, amortizing it over three years beginning April 2016 until fully recovered in 2019,with a return on the return on the unamortized balance.

Project Projections:
No project expenditures are expected in 2019.

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:
2018 O&M expenditures are estimated to be $265k. 2018 Capital expenditures are estimated to be $621k.

Project Progress Summary:
Initial steps in site specific plan development have been completed. Work continues on plans for implementation, decision milestones, compliance approaches, and study requirements. Procurement of long lead time equipment and material in 2018, and selection of contractor services for the Crystal River Project.

Project Projections:
2019 estimated O&M expenditures are $299k, capital expenditures are $4.4M.

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:
Final review of existing FGD Wastewater treatment (WWT) systems across the Duke Energy fleet consisting of physical/chemical and biological technologies, and after several comprehensive design reviews of vendor equipment and balance of plant components, DEF has developed preliminary estimated costs to operate and maintain the CR 4&5 FGD WWT system, which includes employee and contractor labor costs, wastewater treatment chemical costs and material handling and maintenance expenses. Project construction has begun and will continue through February 2019. DEF expects this project to be placed in-service by February 2019.

Project Fiscal Expenditures:
For 2018, 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 $34.1M. Capital expenditures for CAIR/CAMR Crystal River - Conditions of Certification (Project 7.4) are expected to be $45.0M.

Project Progress Summary:
DEF continues to comply with the CAIR, CSAPR and the Acid Rain Program. The FGD WWT project will comply with EPA's CCR rule, ELG requirements, and FDEP's Consent Order OCG Case No. 09-3463D, Third Amendment.

Project Projections:
2019 estimated O&M and capital expenditures are $35.8M and $3.9M respectively.

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 2018.

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 2019.

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, scheduled to be completed by first quarter 2019.
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 idenfitied (MWC-1, MWC-31 and MWC-32). This additional assesment 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:
2018 O&M expenditures are expected to be $170k.

Project Progress Summary:
DEF is evaluating monitoring data and other options to achieve compliance in accordance to Consent Order.

Project Projections:
2019 O&M expenditures are forecasted to be $150k.

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:
2018 Capital expenditures are estimated to be $600, O&M expenditures are also estimated to be $600. Sea turtle nesting season started May 1, 2018, and recently DEF was notified of possible street light issues in Clearwater, FL which may require amber lens installations and/or new lighting.

Project Progress Summary:
DEF is on schedule with activities identified for this program.

Project Projections:
2019 estimated O&M and Capital expenditures are $350 and $400 respectively.

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 2018 estimated expenditures for this project.

Project Progress Summary:
DEF continually evaluates its compliance program, including project prioritization, schedule and technology applications.

Project Projections:
No 2019 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 2018 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 2019 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 2018 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 2019 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 2018 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 2019 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 2018 estimated expenditures for this project.

Project Progress Summary:
The mercury TMDL study concluded in 2012.

Project Projections:
No 2019 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 2018 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA during 2010.

Project Projections:
No 2019 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 2018 estimated expenditures for this project.

Project Progress Summary:
DEF completed and submitted the ICR to EPA in September 2010.

Project Projections:
No 2019 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:
For 2018, capital expenditures are expected to be $911k. O&M is expected to be $40k.

Project Progress Summary:
The first phase of the project will complete construction in 2018, which involves establishing a line from the Ash Sluice Pump Discharge to the FGD Filtrate tanks, and replace the old Sludge Return Pumps with dry seals.

Project Projections:
No 2019 capital or O&M expenditures are forecasted for 2019

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:
2018 O&M expenditures are estimated to be $32k. No capital expenditures are forecasted for 2018.

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:
2019 estimated O&M expenditures are $26k. No capital expenditures are expected in 2019.

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:
2018 O&M expenditures are estimated to be $459K.

Project Progress Summary:
Initial implementation of the CR4&5 MATS compliance plan is complete.

Project Projections:
2019 estimated O&M is $598k. No capital expenditures are forecasted in 2019.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 26
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-1

INDEX

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2017 THROUGH DECEMBER 2017

FORMS 42-1A THROUGH 42-9A

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Tampa Electric Company

Form 42 - 1A

Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017
(in Dollars)

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2017 to December 2017 (Form 42-2A, Lines 5 + 6 + 10)	$8,258,090
2.	Actual/Estimated True-Up Amount Approved for the Period January 2017 to December 2017 (Order No. PSC-2018-0014-FOF-EI)	$6,759,424
3.	Final True-Up to be Refunded/(Recovered) in the Projection Period January 2019 to December 2019 (Lines 1 - 2)	$1,498,666

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

Form 42 - 2A

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)	$5,693,155	$4,999,938	$5,059,411	$5,530,960	$6,443,130	$6,766,223	$7,011,635	$7,316,117	$7,544,533	$6,822,423	$5,689,506	$5,250,302	$74,127,332
2.	True-Up Provision	623,096	623,096	623,096	623,096	623,096	623,096	623,096	623,096	623,096	623,096	623,096	623,101	7,477,157
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	6,316,251	5,623,034	5,682,507	6,154,056	7,066,226	7,389,319	7,634,731	7,939,213	8,167,629	7,445,519	6,312,602	5,873,403	81,604,489
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	1,877,404	1,380,494	2,492,143	2,916,195	1,722,398	1,799,545	1,279,618	1,792,326	1,229,105	2,011,656	912,980	1,773,261	21,187,125
	b. Capital Investment Projects (Form 42-7A, Line 9)	4,426,954	4,415,350	4,404,381	4,396,312	4,386,979	4,377,934	4,328,746	4,318,258	4,306,924	4,294,923	4,282,934	4,271,200	52,210,895
	c. Total Jurisdictional ECRC Costs	6,304,358	5,795,844	6,896,524	7,312,507	6,109,377	6,177,479	5,608,364	6,110,584	5,536,029	6,306,579	5,195,914	6,044,461	73,398,020
5.	Over/Under Recovery (Line 3 - Line 4c)	11,893.00	(172,810)	(1,214,017)	(1,158,451)	956,849.00	1,211,840.00	2,026,367.00	1,828,629.00	2,631,600.00	1,138,940.00	1,116,688.00	(171,058)	8,206,470
6.	Interest Provision (Form 42-3A, Line 10)	3,973	3,372	2,970	2,021	1,479	2,070	3,159	4,314	4,764	5,943	8,130	9,425	51,620
7.	Beginning Balance True-Up & Interest Provision	7,477,157	6,869,927	6,077,393	4,243,250	2,463,724	2,798,956	3,389,770	4,796,200	6,006,047	8,019,315	8,541,102	9,042,824	7,477,157
	a. Deferred True-Up from January to December 2016 (Order No. PSC-16-0535-FOF-EI)	(658,080)	(658,080)	(658,080)	(658,080)	(658,080)	(658,080)	(658,080)	(658,080)	(658,080)	(658,080)	(658,080)	(658,080)	(658,080)
8.	True-Up Collected/(Refunded) (see Line 2)	(623,096)	(623,096)	(623,096)	(623,096)	(623,096)	(623,096)	(623,096)	(623,096)	(623,096)	(623,096)	(623,096)	(623,101)	(7,477,157)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	6,211,847	5,419,313	3,585,170	1,805,644	2,140,876	2,731,690	4,138,120	5,347,967	7,361,235	7,883,022	8,384,744	7,600,010	7,600,010
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)	$6,211,847	$5,419,313	$3,585,170	$1,805,644	$2,140,876	$2,731,690	$4,138,120	$5,347,967	$7,361,235	$7,883,022	$8,384,744	$7,600,010	$7,600,010

Form 42 - 3A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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)	$6,819,077	$6,211,847	$5,419,313	$3,585,170	$1,805,644	$2,140,876	$2,731,690	$4,138,120	$5,347,967	$7,361,235	$7,883,022	$8,384,744	
2.	Ending True-Up Amount Before Interest	6,207,874	5,415,941	3,582,200	1,803,623	2,139,397	2,729,620	4,134,961	5,343,653	7,356,471	7,877,079	8,376,614	7,590,585	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	13,026,951	11,627,788	9,001,513	5,388,793	3,945,041	4,870,496	6,866,651	9,481,773	12,704,438	15,238,314	16,259,636	15,975,329	
4.	Average True-Up Amount (Line 3 x 1/2) [1]	6,513,476	5,813,894	4,500,757	2,694,397	1,972,521	2,435,248	3,433,326	4,740,887	6,352,219	7,619,157	8,129,818	7,987,665	
5.	Interest Rate (First Day of Reporting Business Month)	0.72%	0.74%	0.64%	0.94%	0.86%	0.95%	1.08%	1.12%	1.06%	0.73%	1.14%	1.25%	
6.	Interest Rate (First Day of Subsequent Business Month)	0.74%	0.64%	0.94%	0.86%	0.95%	1.08%	1.12%	1.06%	0.73%	1.14%	1.25%	1.58%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	1.46%	1.38%	1.58%	1.80%	1.81%	2.03%	2.20%	2.18%	1.79%	1.87%	2.39%	2.83%	
8.	Average Interest Rate (Line 7 x 1/2)	0.730%	0.690%	0.790%	0.900%	0.905%	1.015%	1.100%	1.090%	0.895%	0.935%	1.195%	1.415%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.061%	0.058%	0.066%	0.075%	0.075%	0.085%	0.092%	0.091%	0.075%	0.078%	0.100%	0.118%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$3,973	$3,372	$2,970	$2,021	$1,479	$2,070	$3,159	$4,314	$4,764	$5,943	$8,130	$9,425	$51,620

Tampa Electric Company Form 42 - 4A

Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of O&M Activities				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$5,290,620	$5,097,935	$192,685	3.8%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	-	-	-	0.0%
	c. SO_2 Emissions Allowances	(277)	4,339	(4,616)	-106.4%
	d. Big Bend Units 1 & 2 FGD	5,912,375	4,539,203	1,373,172	30.3%
	e. Big Bend PM Minimization and Monitoring	877,242	920,018	(42,776)	-4.6%
	f. Big Bend NO_x Emissions Reduction	513,944	416,153	97,791	23.5%
	g. NPDES Annual Surveillance Fees	34,500	34,500	-	0.0%
	h. Gannon Thermal Discharge Study	-	-	-	0.0%
	i. Polk NO_x Emissions Reduction	21,356	24,114	(2,758)	-11.4%
	j. Bayside SCR Consumables	96,024	92,288	3,736	4.0%
	k. Big Bend Unit 4 SOFA	-	6,000	(6,000)	-100.0%
	l. Big Bend Unit 1 Pre-SCR	41,148	38,810	2,338	6.0%
	m. Big Bend Unit 2 Pre-SCR	462,611	21,733	440,878	2028.6%
	n. Big Bend Unit 3 Pre-SCR	18,707	7,540	11,167	148.1%
	o. Clean Water Act Section 316(b) Phase II Study	516,232	455,438	60,794	13.3%
	p. Arsenic Groundwater Standard Program	79,799	57,227	22,572	39.4%
	q. Big Bend Unit 1 SCR	625,584	970,483	(344,899)	-35.5%
	r. Big Bend Unit 2 SCR	1,718,230	1,750,284	(32,054)	-1.8%
	s. Big Bend Unit 3 SCR	1,369,993	1,221,848	148,145	12.1%
	t. Big Bend Unit 4 SCR	773,126	835,207	(62,081)	-7.4%
	u. Mercury Air Toxics Standards	13,763	68,459	(54,696)	-79.9%
	v. Greenhouse Gas Reduction Program	93,149	93,149	-	0.0%
	w. Big Bend Gypsum Storage Facility	2,035,318	2,309,206	(273,888)	-11.9%
	x. Big Bend Coal Combustion Residuals Rule	679,300	3,626,641	(2,947,341)	-81.3%
	y. Big Bend Effluent Limitations Guidelines Study Program	19,165	197,012	(177,847)	-90.3%
2.	Total Investment Projects - Recoverable Costs	$21,191,909	$22,787,587	(1,595,678)	-7.0%
3.	Recoverable Costs Allocated to Energy	$20,561,378	$22,240,422	(1,679,044)	-7.5%
4.	Recoverable Costs Allocated to Demand	$630,532	$547,165	83,366	15.2%

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-2018-0014-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 2017 to December 2017

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 Flue Gas Desulfurization Integration	455,486	375,834	576,165	591,810	245,025	428,456	498,523	621,432	400,447	655,680	60,351	381,410	$5,290,620		$5,290,620
	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	(75)	3	15	(167)	9	6	(74)	3	2	(34)	17	18	(277)		(277)
	d. Big Bend Units 1 & 2 FGD	575,074	474,544	859,987	1,292,246	509,581	648,293	133,401	110,137	274,784	569,905	259,256	205,167	5,912,375		5,912,375
	e. Big Bend PM Minimization and Monitoring	103,968	38,136	93,681	78,268	70,354	79,611	73,163	65,373	66,238	78,291	81,638	48,522	877,242		877,242
	f. Big Bend NO_x Emissions Reduction	0	0	99,045	60,348	30,073	1,687	45,238	(1,910)	184,105	21,935	69,465	3,957	513,944		513,944
	g. NPDES Annual Surveillance Fees	34,500	0	0	4,479	0	(4,479)	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	
	i. Polk NO_x Emissions Reduction	6,832	5,367	132	929	118	743	4,404	719	228	85	929	869	21,356		21,356
	j. Bayside SCR and Ammonia	10,592	3,703	0	12,778	13,405	3,210	12,370	11,679	3,210	10,469	11,360	3,249	96,024		96,024
	k. Big Bend Unit 4 SOFA		0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR		0	31,995	0	0	815	0	0	8,337	0	0	0	41,148		41,148
	m. Big Bend Unit 2 Pre-SCR		0	14,002	371	635	725	3,441	434,181	7,108	725	0	1,424	462,611		462,611
	n. Big Bend Unit 3 Pre-SCR	725	(725)	725	0	815	0	0	0	0	0	725	16,442	18,707		18,707
	o. Clean Water Act Section 316(b) Phase II Study	5,483	16,813	38,516	35,948	49,811	38,868	97,254	57,150	51,470	37,964	70,922	16,034	516,232	516,232	
	p. Arsenic Groundwater Standard Program	14,784	0	22,963	1,155	17,747	578	10,821	11,751	0	0	0	0	79,799	79,799	
	q. Big Bend Unit 1 SCR	137,349	89,827	55,826	109,624	68,695	25,163	87,863	2,073	3,646	14,681	17,267	13,571	625,584		625,584
	r. Big Bend Unit 2 SCR	137,820	108,993	278,485	248,972	314,195	177,819	(48,828)	78,845	35,348	238,476	126,945	21,159	1,718,230		1,718,230
	s. Big Bend Unit 3 SCR	220,563	47,047	118,496	110,296	65,313	176,133	124,819	195,719	62,922	150,538	26,711	71,436	1,369,993		1,369,993
	t. Big Bend Unit 4 SCR	57,238	55,775	51,423	67,467	49,264	70,040	59,022	88,872	18,880	28,220	47,571	179,355	773,126		773,126
	u. Mercury Air Toxics Standards	(1,000)	0	0	215	268	226	0	4,528	0	0	9,526	0	13,763		13,763
	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	108,723	163,414	246,179	209,918	265,042	145,930	175,123	112,191	109,640	204,722	128,895	165,542	2,035,318		2,035,318
	x. Big Bend Coal Combustion Residuals Rule	9,567	1,833	4,834	149	23,154	6,105	3,566	0	2,738	0	1,402	625,954	679,300		679,300
	y. Big Bend Effluent Limitations Guidelines Study Prograr	0	0	0	0	12	0	0	0	0	0	0	19,153	19,165		19,165
2.	Total of O&M Activities	1,877,629	1,380,563	2,492,469	2,917,956	1,723,516	1,799,929	1,280,103	1,792,744	1,229,105	2,011,656	912,980	1,773,261	21,191,909	$630,532	$20,561,378
3.	Recoverable Costs Allocated to Energy	1,822,862	1,363,750	2,430,990	2,876,374	1,655,958	1,764,962	1,172,029	1,723,843	1,177,635	1,973,692	842,058	1,757,227	20,561,377		
4.	Recoverable Costs Allocated to Demand	54,767	16,813	61,479	41,582	67,558	34,967	108,074	68,901	51,470	37,964	70,922	16,034	630,532		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (A)	1,822,862	1,363,750	2,430,916	2,874,784	1,655,117	1,764,721	1,171,987	1,723,708	1,177,635	1,973,692	842,058	1,757,227	20,558,457		
8.	Jurisdictional Demand Recoverable Costs (B)	54,542	16,744	61,227	41,411	67,281	34,824	107,631	68,618	51,470	37,964	70,922	16,034	628,668		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,877,404	$1,380,494	$2,492,143	$2,916,195	$1,722,398	$1,799,545	$1,279,618	$1,792,326	1,229,105	2,011,656	$912,980	$1,773,261	$21,187,125		

Notes:
(A) Line 3 x Line 5
(B) Line 4 x Line 6

Tampa Electric Company Form 42 - 6A

Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$1,098,902	$1,098,902	$0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	276,598	276,598	0	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	57,669	57,669	0	0.0%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	37,488	37,488	0	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	61,658	61,658	0	0.0%
	f. Big Bend Unit 1 Classifier Replacement	89,946	89,946	0	0.0%
	g. Big Bend Unit 2 Classifier Replacement	65,159	65,159	0	0.0%
	h. Big Bend Section 114 Mercury Testing Platform	9,760	9,760	0	0.0%
	i. Big Bend Units 1 & 2 FGD	6,843,158	6,857,459	(14,301)	-0.2%
	j. Big Bend FGD Optimization and Utilization	1,714,824	1,714,824	0	0.0%
	k. Big Bend NO_x Emissions Reduction	576,255	576,255	0	0.0%
	l. Big Bend PM Minimization and Monitoring	2,063,180	2,063,180	0	0.0%
	m. Polk NO_x Emissions Reduction	128,558	128,558	0	0.0%
	n. Big Bend Unit 4 SOFA	226,319	226,319	0	0.0%
	o. Big Bend Unit 1 Pre-SCR	156,044	156,044	0	0.0%
	p. Big Bend Unit 2 Pre-SCR	148,634	148,634	0	0.0%
	q. Big Bend Unit 3 Pre-SCR	265,762	265,762	0	0.0%
	r. Big Bend Unit 1 SCR	9,021,509	9,020,389	1,120	0.0%
	s. Big Bend Unit 2 SCR	9,561,175	9,561,175	0	0.0%
	t. Big Bend Unit 3 SCR	7,913,597	7,913,597	0	0.0%
	u. Big Bend Unit 4 SCR	6,145,021	6,145,021	0	0.0%
	v. Big Bend FGD System Reliability	2,391,870	2,391,870	0	0.0%
	w. Mercury Air Toxics Standards	932,645	932,645	0	0.0%
	x. SO_2 Emissions Allowances	(3,071)	(3,070)	(1)	0.0%
	y. Big Bend Gypsum Storage Facility	2,383,083	2,383,083	0	0.0%
	z. Big Bend Coal Combustion Residuals Rule	51,396	59,761	(8,365)	-14.0%
2.	Total Investment Projects - Recoverable Costs	$52,217,139	$52,238,686	($21,547)	0.0%
3.	Recoverable Costs Allocated to Energy	$52,066,597	$52,079,779	($13,182)	0.0%
4.	Recoverable Costs Allocated to Demand	$150,542	$158,907	($8,365)	-5.3%

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-2018-0014-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 2017 to December 2017

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description (A)		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	1	$93,182	$92,967	$92,753	$92,538	$92,325	$92,110	$91,033	$90,822	$90,610	$90,399	$90,187	$89,976	$1,098,902		$1,098,902
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	23,755	23,635	23,515	23,395	23,275	23,154	22,941	22,823	22,704	22,585	22,467	22,349	276,598		276,598
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	4,917	4,900	4,882	4,866	4,848	4,831	4,780	4,763	4,746	4,729	4,712	4,695	57,669		57,669
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4	3,194	3,182	3,172	3,162	3,152	3,141	3,106	3,096	3,086	3,076	3,066	3,055	37,488	$37,488	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	5	5,252	5,235	5,217	5,200	5,183	5,166	5,110	5,093	5,076	5,059	5,042	5,025	61,658	61,658	
	f.	Big Bend Unit 1 Classifier Replacement	6	7,695	7,663	7,631	7,598	7,565	7,533	7,457	7,425	7,393	7,361	7,328	7,297	89,946		89,946
	g.	Big Bend Unit 2 Classifier Replacement	7	5,570	5,547	5,525	5,503	5,480	5,457	5,402	5,379	5,358	5,335	5,313	5,290	65,159		65,159
	h.	Big Bend Section 114 Mercury Testing Platform	8	829	827	824	823	820	818	808	806	805	802	800	798	9,760		9,760
	i.	Big Bend Units 1 & 2 FGD	9	583,056	581,109	579,162	577,214	575,267	573,319	567,140	565,220	563,299	561,378	559,457	557,537	6,843,158		6,843,158
	j.	Big Bend FGD Optimization and Utilization	10	145,418	145,082	144,745	144,409	144,072	143,736	142,057	141,725	141,393	141,061	140,729	140,397	1,714,824		1,714,824
	k.	Big Bend NO_x Emissions Reduction	11	48,696	48,621	48,545	48,469	48,394	48,318	47,722	47,648	47,572	47,498	47,423	47,349	576,255		576,255
	l.	Big Bend PM Minimization and Monitoring	12	175,176	174,724	174,271	173,819	173,365	172,913	170,935	170,489	170,042	169,595	169,149	168,702	2,063,180		2,063,180
	m.	Polk NO_x Emissions Reduction	13	10,937	10,904	10,871	10,838	10,805	10,772	10,653	10,621	10,588	10,555	10,523	10,491	128,558		128,558
	n.	Big Bend Unit 4 SOFA	14	19,206	19,159	19,111	19,064	19,016	18,969	18,750	18,702	18,656	18,609	18,562	18,515	226,319		226,319
	o.	Big Bend Unit 1 Pre-SCR	15	13,280	13,238	13,197	13,157	13,116	13,075	12,931	12,891	12,851	12,810	12,769	12,729	156,044		156,044
	p.	Big Bend Unit 2 Pre-SCR	16	12,637	12,600	12,564	12,528	12,491	12,455	12,316	12,280	12,245	12,208	12,173	12,137	148,634		148,634
	q.	Big Bend Unit 3 Pre-SCR	17	22,569	22,509	22,451	22,391	22,331	22,273	22,019	21,961	21,902	21,844	21,785	21,727	265,762		265,762
	r.	Big Bend Unit 1 SCR	18	765,659	763,374	761,095	758,818	757,827	756,840	748,565	746,401	744,133	741,866	739,599	737,332	9,021,509		9,021,509
	s.	Big Bend Unit 2 SCR	19	812,671	810,382	808,094	805,805	803,516	801,228	792,223	789,966	787,709	785,451	783,193	780,937	9,561,175		9,561,175
	t.	Big Bend Unit 3 SCR	20	667,963	666,304	665,056	668,330	666,907	665,005	656,960	655,112	653,262	651,414	649,566	647,718	7,913,597		7,913,597
	u.	Big Bend Unit 4 SCR	21	521,965	520,570	519,174	517,778	516,383	514,988	509,135	507,759	506,382	505,006	503,629	502,252	6,145,021		6,145,021
	v.	Big Bend FGD System Reliability	22	202,432	202,051	201,669	201,287	200,905	200,524	198,108	197,731	197,355	196,979	196,603	196,226	2,391,870		2,391,870
	w.	Mercury Air Toxics Standards	23	78,996	78,834	78,671	78,508	78,346	78,182	77,253	77,092	76,931	76,771	76,611	76,450	932,645		932,645
	x.	SO_2 Emissions Allowances	24	(259)	(258)	(258)	(258)	(258)	(258)	(254)	(254)	(254)	(254)	(253)	(253)	(3,071)		(3,071)
	y.	Big Bend Gypsum Storage Facility	25	201,687	201,305	200,922	200,548	200,180	199,796	197,392	197,012	196,631	196,251	195,870	195,489	2,383,083		2,383,083
	z.	Big Bend Coal Combustion Residuals Rule	26	508	924	1,697	2,994	3,941	4,236	4,409	6,092	6,449	6,535	6,631	6,980	51,396	51,396	
2.		Total Investment Projects - Recoverable Costs		4,426,991	4,415,388	4,404,556	4,398,784	4,389,252	4,378,581	4,328,951	4,318,655	4,306,924	4,294,923	4,282,934	4,271,200	52,217,139	$150,542	$52,066,597
3.		Recoverable Costs Allocated to Energy		4,418,037	4,406,047	4,394,470	4,387,428	4,376,976	4,366,038	4,316,326	4,304,374	4,292,313	4,280,253	4,268,195	4,256,140	52,066,597		52,066,597
4.		Recoverable Costs Allocated to Demand		8,954	9,341	10,086	11,356	12,276	12,543	12,625	14,281	14,611	14,670	14,739	15,060	150,542	150,542	
5.		Retail Energy Jurisdictional Factor		1.0000000	1.0000000	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000			
6.		Retail Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000			
7.		Jurisdictional Energy Recoverable Costs (C)		4,418,037	4,406,047	4,394,336	4,385,003	4,374,753	4,365,442	4,316,173	4,304,036	4,292,313	4,280,253	4,268,195	4,256,140	52,060,728		
8.		Jurisdictional Demand Recoverable Costs (D)		8,917	9,303	10,045	11,309	12,226	12,492	12,573	14,222	14,611	14,670	14,739	15,060	150,167		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$4,426,954	$4,415,350	$4,404,381	$4,396,312	$4,386,979	$4,377,934	$4,328,746	$4,318,258	$4,306,924	$4,294,923	$4,282,934	$4,271,200	$52,210,895		

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

DOCKET NO. 20180007-EI
ECRC 2017 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 7, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	
3.	Less: Accumulated Depreciation	(5,094,244)	(5,123,081)	(5,151,918)	(5,180,755)	(5,209,592)	(5,238,429)	(5,267,266)	(5,296,103)	(5,324,940)	(5,353,777)	(5,382,614)	(5,411,451)	(5,440,288)	
4.	CWIP - Non-Interest Bearing	-	0	0	0	0	0	0	0	0	0	0	0	-	
5.	Net Investment (Lines 2 + 3 + 4)	$8,668,837	8,640,000	8,611,163	8,582,326	8,553,489	8,524,652	8,495,815	8,466,978	8,438,141	8,409,304	8,380,467	8,351,630	8,322,793	
6.	Average Net Investment		8,654,419	8,625,582	8,596,745	8,567,908	8,539,071	8,510,234	8,481,397	8,452,560	8,423,723	8,394,886	8,366,049	8,337,212	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		50,681	50,512	50,343	50,174	50,006	49,837	49,503	49,335	49,166	48,998	48,830	48,662	$596,047
	b. Debt Component Grossed Up For Taxes (C)		13,664	13,618	13,573	13,527	13,482	13,436	12,693	12,650	12,607	12,564	12,520	12,477	156,811
8.	Investment Expenses														
	a. Depreciation (D)		28,837	28,837	28,837	28,837	28,837	28,837	28,837	28,837	28,837	28,837	28,837	28,837	346,044
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		93,182	92,967	92,753	92,538	92,325	92,110	91,033	90,822	90,610	90,399	90,187	89,976	1,098,902
	a. Recoverable Costs Allocated to Energy		93,182	92,967	92,753	92,538	92,325	92,110	91,033	90,822	90,610	90,399	90,187	89,976	1,098,902
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		93,182	92,967	92,750	92,487	92,278	92,097	91,030	90,815	90,610	90,399	90,187	89,976	1,098,778
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)		$93,182	$92,967	$92,750	$92,487	$92,278	$92,097	$91,030	$90,815	$90,610	$90,399	$90,187	$89,976	$1,098,778

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775) and 315.45 ($327,307)
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2017 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 2017 to December 2017

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	(3,985,586)	(4,001,727)	(4,017,868)	(4,034,009)	(4,050,150)	(4,066,291)	(4,082,432)	(4,098,573)	(4,114,714)	(4,130,855)	(4,146,996)	(4,163,137)	(4,179,278)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,032,148	1,016,007	999,866	983,725	967,584	951,443	935,302	919,161	903,020	886,879	870,738	854,597	838,456	
6.	Average Net Investment		1,024,078	1,007,937	991,796	975,655	959,514	943,373	927,232	911,091	894,950	878,809	862,668	846,527	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,997	5,903	5,808	5,714	5,619	5,524	5,412	5,318	5,224	5,129	5,035	4,941	$65,624
	b. Debt Component Grossed Up For Taxes (C)		1,617	1,591	1,566	1,540	1,515	1,489	1,388	1,364	1,339	1,315	1,291	1,267	17,282
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)		23,755	23,635	23,515	23,395	23,275	23,154	22,941	22,823	22,704	22,585	22,467	22,349	276,598
	a. Recoverable Costs Allocated to Energy		23,755	23,635	23,515	23,395	23,275	23,154	22,941	22,823	22,704	22,585	22,467	22,349	276,598
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		23,755	23,635	23,514	23,382	23,263	23,151	22,940	22,821	22,704	22,585	22,467	22,349	276,566
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)		$23,755	$23,635	$23,514	$23,382	$23,263	$23,151	$22,940	$22,821	$22,704	$22,585	$22,467	$22,349	$276,566

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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	(514,445)	(516,755)	(519,065)	(521,375)	(523,685)	(525,995)	(528,305)	(530,615)	(532,925)	(535,235)	(537,545)	(539,855)	(542,165)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$351,766	349,456	347,146	344,836	342,526	340,216	337,906	335,596	333,286	330,976	328,666	326,356	324,046	
6.	Average Net Investment		350,611	348,301	345,991	343,681	341,371	339,061	336,751	334,441	332,131	329,821	327,511	325,201	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,053	2,040	2,026	2,013	1,999	1,986	1,966	1,952	1,939	1,925	1,912	1,898	$23,709
	b. Debt Component Grossed Up For Taxes (C)		554	550	546	543	539	535	504	501	497	494	490	487	6,240
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)		4,917	4,900	4,882	4,866	4,848	4,831	4,780	4,763	4,746	4,729	4,712	4,695	57,669
	a. Recoverable Costs Allocated to Energy		4,917	4,900	4,882	4,866	4,848	4,831	4,780	4,763	4,746	4,729	4,712	4,695	57,669
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,917	4,900	4,882	4,863	4,846	4,830	4,780	4,763	4,746	4,729	4,712	4,695	57,663
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)		$4,917	$4,900	$4,882	$4,863	$4,846	$4,830	$4,780	$4,763	$4,746	$4,729	$4,712	$4,695	$57,663

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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	(257,032)	(258,442)	(259,852)	(261,262)	(262,672)	(264,082)	(265,492)	(266,902)	(268,312)	(269,722)	(271,132)	(272,542)	(273,952)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$240,546	239,136	237,726	236,316	234,906	233,496	232,086	230,676	229,266	227,856	226,446	225,036	223,626	
6.	Average Net Investment		239,841	238,431	237,021	235,611	234,201	232,791	231,381	229,971	228,561	227,151	225,741	224,331	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		1,405	1,396	1,388	1,380	1,372	1,363	1,350	1,342	1,334	1,326	1,318	1,309	$16,283
	b. Debt Component Grossed Up For Taxes (C)		379	376	374	372	370	368	346	344	342	340	338	336	4,285
8.	Investment Expenses														
	a. Depreciation (D)		$1,410	$1,410	$1,410	$1,410	$1,410	$1,410	$1,410	$1,410	$1,410	$1,410	$1,410	$1,410	16,920
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		3,194	3,182	3,172	3,162	3,152	3,141	3,106	3,096	3,086	3,076	3,066	3,055	37,488
	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		3,194	3,182	3,172	3,162	3,152	3,141	3,106	3,096	3,086	3,076	3,066	3,055	37,488
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	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)		3,181	3,169	3,159	3,149	3,139	3,128	3,093	3,083	3,086	3,076	3,066	3,055	37,384
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$3,181	$3,169	$3,159	$3,149	$3,139	$3,128	$3,093	$3,083	$3,086	$3,076	$3,066	$3,055	$37,384

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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 (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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	(422,764)	(425,083)	(427,402)	(429,721)	(432,040)	(434,359)	(436,678)	(438,997)	(441,316)	(443,635)	(445,954)	(448,273)	(450,592)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$395,637	393,318	390,999	388,680	386,361	384,042	381,723	379,404	377,085	374,766	372,447	370,128	367,809	
6.	Average Net Investment		394,478	392,159	389,840	387,521	385,202	382,883	380,564	378,245	375,926	373,607	371,288	368,969	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,310	2,297	2,283	2,269	2,256	2,242	2,221	2,208	2,194	2,181	2,167	2,154	$26,782
	b. Debt Component Grossed Up For Taxes (C)		623	619	615	612	608	605	570	566	563	559	556	552	7,048
8.	Investment Expenses														
	a. Depreciation (D)		$2,319	$2,319	$2,319	$2,319	$2,319	$2,319	$2,319	$2,319	$2,319	$2,319	$2,319	$2,319	27,828
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		5,252	5,235	5,217	5,200	5,183	5,166	5,110	5,093	5,076	5,059	5,042	5,025	61,658
	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		5,252	5,235	5,217	5,200	5,183	5,166	5,110	5,093	5,076	5,059	5,042	5,025	61,658
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	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)		5,230	5,214	5,196	5,179	5,162	5,145	5,089	5,072	5,076	5,059	5,042	5,025	61,489
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$5,230	$5,214	$5,196	$5,179	$5,162	$5,145	$5,089	$5,072	$5,076	$5,059	$5,042	$5,025	$61,489

Notes:

(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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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ECRC 2017 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 2017 to December 2017

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	(869,192)	(873,580)	(877,968)	(882,356)	(886,744)	(891,132)	(895,520)	(899,908)	(904,296)	(908,684)	(913,072)	(917,460)	(921,848)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$447,065	442,677	438,289	433,901	429,513	425,125	420,737	416,349	411,961	407,573	403,185	398,797	394,409	
6.	Average Net Investment		444,871	440,483	436,095	431,707	427,319	422,931	418,543	414,155	409,767	405,379	400,991	396,603	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,605	2,580	2,554	2,528	2,502	2,477	2,443	2,417	2,392	2,366	2,340	2,315	$29,519
	b. Debt Component Grossed Up For Taxes (C)		702	695	689	682	675	668	626	620	613	607	600	594	7,771
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)		7,695	7,663	7,631	7,598	7,565	7,533	7,457	7,425	7,393	7,361	7,328	7,297	89,946
	a. Recoverable Costs Allocated to Energy		7,695	7,663	7,631	7,598	7,565	7,533	7,457	7,425	7,393	7,361	7,328	7,297	89,946
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		7,695	7,663	7,631	7,594	7,561	7,532	7,457	7,424	7,393	7,361	7,328	7,297	89,936
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,695	$7,663	$7,631	$7,594	$7,561	$7,532	$7,457	$7,424	$7,393	$7,361	$7,328	$7,297	$89,936

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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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ECRC 2017 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 2017 to December 2017

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	(642,438)	(645,474)	(648,510)	(651,546)	(654,582)	(657,618)	(660,654)	(663,690)	(666,726)	(669,762)	(672,798)	(675,834)	(678,870)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$342,356	339,320	336,284	333,248	330,212	327,176	324,140	321,104	318,068	315,032	311,996	308,960	305,924	
6.	Average Net Investment		340,838	337,802	334,766	331,730	328,694	325,658	322,622	319,586	316,550	313,514	310,478	307,442	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		1,996	1,978	1,960	1,943	1,925	1,907	1,883	1,865	1,848	1,830	1,812	1,794	$22,741
	b. Debt Component Grossed Up For Taxes (C)		538	533	529	524	519	514	483	478	474	469	465	460	5,986
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)		5,570	5,547	5,525	5,503	5,480	5,457	5,402	5,379	5,358	5,335	5,313	5,290	65,159
	a. Recoverable Costs Allocated to Energy		5,570	5,547	5,525	5,503	5,480	5,457	5,402	5,379	5,358	5,335	5,313	5,290	65,159
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		5,570	5,547	5,525	5,500	5,477	5,456	5,402	5,379	5,358	5,335	5,313	5,290	65,152
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)		$5,570	$5,547	$5,525	$5,500	$5,477	$5,456	$5,402	$5,379	$5,358	$5,335	$5,313	$5,290	$65,152

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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	(48,403)	(48,695)	(48,987)	(49,279)	(49,571)	(49,863)	(50,155)	(50,447)	(50,739)	(51,031)	(51,323)	(51,615)	(51,907)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$72,334	72,042	71,750	71,458	71,166	70,874	70,582	70,290	69,998	69,706	69,414	69,122	68,830	
6.	Average Net Investment		72,188	71,896	71,604	71,312	71,020	70,728	70,436	70,144	69,852	69,560	69,268	68,976	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		423	421	419	418	416	414	411	409	408	406	404	403	$4,952
	b. Debt Component Grossed Up For Taxes (C)		114	114	113	113	112	112	105	105	105	104	104	103	1,304
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)		829	827	824	823	820	818	808	806	805	802	800	798	9,760
	a. Recoverable Costs Allocated to Energy		829	827	824	823	820	818	808	806	805	802	800	798	9,760
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		829	827	824	823	820	818	808	806	805	802	800	798	9,760
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)		$829	$827	$824	$823	$820	$818	$808	$806	$805	$802	$800	$798	$9,760

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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 2017 to December 2017

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	(51,931,181)	(52,193,100)	(52,455,019)	(52,716,938)	(52,978,857)	(53,240,776)	(53,502,695)	(53,764,614)	(54,026,533)	(54,288,452)	(54,550,371)	(54,812,290)	(55,074,209)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$43,324,061	43,062,142	42,800,223	42,538,304	42,276,385	42,014,466	41,752,547	41,490,628	41,228,709	40,966,790	40,704,871	40,442,952	40,181,033	
6.	Average Net Investment		43,193,101	42,931,182	42,669,263	42,407,344	42,145,425	41,883,506	41,621,587	41,359,668	41,097,749	40,835,830	40,573,911	40,311,992	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		252,942	251,409	249,875	248,341	246,807	245,273	242,931	241,403	239,874	238,345	236,816	235,288	$2,929,304
	b. Debt Component Grossed Up For Taxes (C)		68,195	67,781	67,368	66,954	66,541	66,127	62,290	61,898	61,506	61,114	60,722	60,330	770,826
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)		583,056	581,109	579,162	577,214	575,267	573,319	567,140	565,220	563,299	561,378	559,457	557,537	6,843,158
	a. Recoverable Costs Allocated to Energy		583,056	581,109	579,162	577,214	575,267	573,319	567,140	565,220	563,299	561,378	559,457	557,537	6,843,158
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		583,056	581,109	579,144	576,895	574,975	573,241	567,120	565,176	563,299	561,378	559,457	557,537	6,842,387
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)		$583,056	$581,109	$579,144	$576,895	$574,975	$573,241	$567,120	$565,176	$563,299	$561,378	$559,457	$557,537	$6,842,387

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 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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 (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(8,247,637)	(8,292,911)	(8,338,185)	(8,383,459)	(8,428,733)	(8,474,007)	(8,519,281)	(8,564,555)	(8,609,829)	(8,655,103)	(8,700,377)	(8,745,651)	(8,790,925)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$13,492,100	13,446,826	13,401,552	13,356,278	13,311,004	13,265,730	13,220,456	13,175,182	13,129,908	13,084,634	13,039,360	12,994,086	12,948,812	
6.	Average Net Investment		13,469,463	13,424,189	13,378,915	13,333,641	13,288,367	13,243,093	13,197,819	13,152,545	13,107,271	13,061,997	13,016,723	12,971,449	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		78,878	78,613	78,348	78,083	77,818	77,553	77,031	76,767	76,503	76,239	75,974	75,710	$927,517
	b. Debt Component Grossed Up For Taxes (C)		21,266	21,195	21,123	21,052	20,980	20,909	19,752	19,684	19,616	19,548	19,481	19,413	244,019
8.	Investment Expenses														
	a. Depreciation (D)		$45,274	$45,274	$45,274	$45,274	$45,274	$45,274	$45,274	$45,274	$45,274	$45,274	$45,274	$45,274	543,288
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		145,418	145,082	144,745	144,409	144,072	143,736	142,057	141,725	141,393	141,061	140,729	140,397	1,714,824
	a. Recoverable Costs Allocated to Energy		145,418	145,082	144,745	144,409	144,072	143,736	142,057	141,725	141,393	141,061	140,729	140,397	1,714,824
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		145,418	145,082	144,741	144,329	143,999	143,716	142,052	141,714	141,393	141,061	140,729	140,397	1,714,631
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)		$145,418	$145,082	$144,741	$144,329	$143,999	$143,716	$142,052	$141,714	$141,393	$141,061	$140,729	$140,397	$1,714,631

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($21,699,919)and 311.45 ($39,818)
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5% and 2.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20180007-EI
ECRC 2017 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 10 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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	1,994,187	1,984,003	1,973,819	1,963,635	1,953,451	1,943,267	1,933,083	1,922,899	1,912,715	1,902,531	1,892,347	1,882,163	1,871,979	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,185,039	5,174,855	5,164,671	5,154,487	5,144,303	5,134,119	5,123,935	5,113,751	5,103,567	5,093,383	5,083,199	5,073,015	5,062,831	
6.	Average Net Investment		5,179,947	5,169,763	5,159,579	5,149,395	5,139,211	5,129,027	5,118,843	5,108,659	5,098,475	5,088,291	5,078,107	5,067,923	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		30,334	30,275	30,215	30,155	30,096	30,036	29,877	29,818	29,758	29,699	29,639	29,580	$359,482
	b. Debt Component Grossed Up For Taxes (C)		8,178	8,162	8,146	8,130	8,114	8,098	7,661	7,646	7,630	7,615	7,600	7,585	94,565
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)		48,696	48,621	48,545	48,469	48,394	48,318	47,722	47,648	47,572	47,498	47,423	47,349	576,255
	a. Recoverable Costs Allocated to Energy		48,696	48,621	48,545	48,469	48,394	48,318	47,722	47,648	47,572	47,498	47,423	47,349	576,255
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		48,696	48,621	48,544	48,442	48,369	48,311	47,720	47,644	47,572	47,498	47,423	47,349	576,189
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)		$48,696	$48,621	$48,544	$48,442	$48,369	$48,311	$47,720	$47,644	$47,572	$47,498	$47,423	$47,349	$576,189

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 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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

DOCKET NO. 20180007-EI
ECRC 2017 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 11 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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)	$19,757,774	$19,757,774	$19,757,774	$19,757,774	$19,757,774	$19,757,774	$19,757,774	$19,757,774	$19,757,774	$19,757,774	$19,757,774	$19,757,774	$19,757,774	
3.	Less: Accumulated Depreciation	(4,353,394)	(4,414,266)	(4,475,138)	(4,536,010)	(4,596,882)	(4,657,754)	(4,718,626)	(4,779,498)	(4,840,370)	(4,901,242)	(4,962,114)	(5,022,986)	(5,083,858)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$15,404,380	15,343,508	15,282,636	15,221,764	15,160,892	15,100,020	15,039,148	14,978,276	14,917,404	14,856,532	14,795,660	14,734,788	14,673,916	
6.	Average Net Investment		15,373,944	15,313,072	15,252,200	15,191,328	15,130,456	15,069,584	15,008,712	14,947,840	14,886,968	14,826,096	14,765,224	14,704,352	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		90,031	89,675	89,318	88,962	88,605	88,249	87,601	87,246	86,890	86,535	86,180	85,824	$1,055,116
	b. Debt Component Grossed Up For Taxes (C)		24,273	24,177	24,081	23,985	23,888	23,792	22,462	22,371	22,280	22,188	22,097	22,006	277,600
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)		175,176	174,724	174,271	173,819	173,365	172,913	170,935	170,489	170,042	169,595	169,149	168,702	2,063,180
	a. Recoverable Costs Allocated to Energy		175,176	174,724	174,271	173,819	173,365	172,913	170,935	170,489	170,042	169,595	169,149	168,702	2,063,180
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		175,176	174,724	174,266	173,723	173,277	172,889	170,929	170,476	170,042	169,595	169,149	168,702	2,062,948
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$175,176	$174,724	$174,266	$173,723	$173,277	$172,889	$170,929	$170,476	$170,042	$169,595	$169,149	$168,702	$2,062,948

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($5,831,489), 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 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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	(683,322)	(687,746)	(692,170)	(696,594)	(701,018)	(705,442)	(709,866)	(714,290)	(718,714)	(723,138)	(727,562)	(731,986)	(736,410)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$878,151	873,727	869,303	864,879	860,455	856,031	851,607	847,183	842,759	838,335	833,911	829,487	825,063	
6.	Average Net Investment		875,939	871,515	867,091	862,667	858,243	853,819	849,395	844,971	840,547	836,123	831,699	827,275	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,130	5,104	5,078	5,052	5,026	5,000	4,958	4,932	4,906	4,880	4,854	4,829	$59,749
	b. Debt Component Grossed Up For Taxes (C)		1,383	1,376	1,369	1,362	1,355	1,348	1,271	1,265	1,258	1,251	1,245	1,238	15,721
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)		10,937	10,904	10,871	10,838	10,805	10,772	10,653	10,621	10,588	10,555	10,523	10,491	128,558
	a. Recoverable Costs Allocated to Energy		10,937	10,904	10,871	10,838	10,805	10,772	10,653	10,621	10,588	10,555	10,523	10,491	128,558
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		10,937	10,904	10,871	10,832	10,800	10,771	10,653	10,620	10,588	10,555	10,523	10,491	128,545
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)		$10,937	$10,904	$10,871	$10,832	$10,800	$10,771	$10,653	$10,620	$10,588	$10,555	$10,523	$10,491	$128,545

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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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ECRC 2017 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 2017 to December 2017

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	(832,670)	(839,067)	(845,464)	(851,861)	(858,258)	(864,655)	(871,052)	(877,449)	(883,846)	(890,243)	(896,640)	(903,037)	(909,434)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,726,060	1,719,663	1,713,266	1,706,869	1,700,472	1,694,075	1,687,678	1,681,281	1,674,884	1,668,487	1,662,090	1,655,693	1,649,296	
6.	Average Net Investment		1,722,862	1,716,465	1,710,068	1,703,671	1,697,274	1,690,877	1,684,480	1,678,083	1,671,686	1,665,289	1,658,892	1,652,495	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,089	10,052	10,014	9,977	9,939	9,902	9,832	9,794	9,757	9,720	9,682	9,645	$118,403
	b. Debt Component Grossed Up For Taxes (C)		2,720	2,710	2,700	2,690	2,680	2,670	2,521	2,511	2,502	2,492	2,483	2,473	31,152
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)		19,206	19,159	19,111	19,064	19,016	18,969	18,750	18,702	18,656	18,609	18,562	18,515	226,319
	a. Recoverable Costs Allocated to Energy		19,206	19,159	19,111	19,064	19,016	18,969	18,750	18,702	18,656	18,609	18,562	18,515	226,319
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		19,206	19,159	19,110	19,053	19,006	18,966	18,749	18,701	18,656	18,609	18,562	18,515	226,292
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$19,206	$19,159	$19,110	$19,053	$19,006	$18,966	$18,749	$18,701	$18,656	$18,609	$18,562	$18,515	$226,292

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20180007-EI
ECRC 2017 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 2017 to December 2017

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	(599,665)	(605,162)	(610,659)	(616,156)	(621,653)	(627,150)	(632,647)	(638,144)	(643,641)	(649,138)	(654,635)	(660,132)	(665,629)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,049,456	1,043,959	1,038,462	1,032,965	1,027,468	1,021,971	1,016,474	1,010,977	1,005,480	999,983	994,486	988,989	983,492	
6.	Average Net Investment		1,046,708	1,041,211	1,035,714	1,030,217	1,024,720	1,019,223	1,013,726	1,008,229	1,002,732	997,235	991,738	986,241	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,130	6,097	6,065	6,033	6,001	5,969	5,917	5,885	5,853	5,821	5,788	5,756	$71,315
	b. Debt Component Grossed Up For Taxes (C)		1,653	1,644	1,635	1,627	1,618	1,609	1,517	1,509	1,501	1,492	1,484	1,476	18,765
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)		13,280	13,238	13,197	13,157	13,116	13,075	12,931	12,891	12,851	12,810	12,769	12,729	156,044
	a. Recoverable Costs Allocated to Energy		13,280	13,238	13,197	13,157	13,116	13,075	12,931	12,891	12,851	12,810	12,769	12,729	156,044
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		13,280	13,238	13,197	13,150	13,109	13,073	12,931	12,890	12,851	12,810	12,769	12,729	156,027
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)		$13,280	$13,238	$13,197	$13,150	$13,109	$13,073	$12,931	$12,890	$12,851	$12,810	$12,769	$12,729	$156,027

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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 2017 to December 2017

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	(535,796)	(540,673)	(545,550)	(550,427)	(555,304)	(560,181)	(565,058)	(569,935)	(574,812)	(579,689)	(584,566)	(589,443)	(594,320)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,046,091	1,041,214	1,036,337	1,031,460	1,026,583	1,021,706	1,016,829	1,011,952	1,007,075	1,002,198	997,321	992,444	987,567	
6.	Average Net Investment		1,043,653	1,038,776	1,033,899	1,029,022	1,024,145	1,019,268	1,014,391	1,009,514	1,004,637	999,760	994,883	990,006	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,112	6,083	6,055	6,026	5,997	5,969	5,921	5,892	5,864	5,835	5,807	5,778	$71,339
	b. Debt Component Grossed Up For Taxes (C)		1,648	1,640	1,632	1,625	1,617	1,609	1,518	1,511	1,504	1,496	1,489	1,482	18,771
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)		12,637	12,600	12,564	12,528	12,491	12,455	12,316	12,280	12,245	12,208	12,173	12,137	148,634
	a. Recoverable Costs Allocated to Energy		12,637	12,600	12,564	12,528	12,491	12,455	12,316	12,280	12,245	12,208	12,173	12,137	148,634
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		12,637	12,600	12,564	12,521	12,485	12,453	12,316	12,279	12,245	12,208	12,173	12,137	148,618
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)		$12,637	$12,600	$12,564	$12,521	$12,485	$12,453	$12,316	$12,279	$12,245	$12,208	$12,173	$12,137	$148,618

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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 (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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	(736,766)	(744,719)	(752,672)	(760,625)	(768,578)	(776,531)	(784,484)	(792,437)	(800,390)	(808,343)	(816,296)	(824,249)	(832,202)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,969,741	1,961,788	1,953,835	1,945,882	1,937,929	1,929,976	1,922,023	1,914,070	1,906,117	1,898,164	1,890,211	1,882,258	1,874,305	
6.	Average Net Investment		1,965,765	1,957,812	1,949,859	1,941,906	1,933,953	1,926,000	1,918,047	1,910,094	1,902,141	1,894,188	1,886,235	1,878,282	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		11,512	11,465	11,419	11,372	11,325	11,279	11,195	11,149	11,102	11,056	11,009	10,963	$134,846
	b. Debt Component Grossed Up For Taxes (C)		3,104	3,091	3,079	3,066	3,053	3,041	2,871	2,859	2,847	2,835	2,823	2,811	35,480
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)		22,569	22,509	22,451	22,391	22,331	22,273	22,019	21,961	21,902	21,844	21,785	21,727	265,762
	a. Recoverable Costs Allocated to Energy		22,569	22,509	22,451	22,391	22,331	22,273	22,019	21,961	21,902	21,844	21,785	21,727	265,762
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		22,569	22,509	22,450	22,379	22,320	22,270	22,018	21,959	21,902	21,844	21,785	21,727	265,732
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)		$22,569	$22,509	$22,450	$22,379	$22,320	$22,270	$22,018	$21,959	$21,902	$21,844	$21,785	$21,727	$265,732

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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 (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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		$2,030	$1,471	$3,693	$2,348	$349,430	$3,424	$27,700	$39	$0	$0	$0	$0	$390,136
	b. Clearings to Plant		0	0	0	0	0	0	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	(25,139,646)	(25,448,812)	(25,757,978)	(26,067,144)	(26,376,310)	(26,685,476)	(26,994,642)	(27,303,808)	(27,612,974)	(27,922,140)	(28,231,306)	(28,540,472)	(28,849,638)	
4.	CWIP - Non-Interest Bearing	972,688	974,718	976,189	979,882	982,231	1,331,661	1,335,085	1,362,785	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	
5.	Net Investment (Lines 2 + 3 + 4)	$61,552,144	61,245,008	60,937,313	60,631,840	60,325,022	60,365,287	60,059,545	59,778,078	59,468,952	59,159,786	58,850,620	58,541,454	58,232,288	
6.	Average Net Investment		61,398,576	61,091,160	60,784,576	60,478,431	60,345,154	60,212,416	59,918,812	59,623,515	59,314,369	59,005,203	58,696,037	58,386,871	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		359,555	357,755	355,960	354,167	353,386	352,609	349,726	348,003	346,198	344,394	342,589	340,785	$4,205,127
	b. Debt Component Grossed Up For Taxes (C)		96,938	96,453	95,969	95,485	95,275	95,065	89,673	89,232	88,769	88,306	87,844	87,381	1,106,390
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)		765,659	763,374	761,095	758,818	757,827	756,840	748,565	746,401	744,133	741,866	739,599	737,332	9,021,509
	a. Recoverable Costs Allocated to Energy		765,659	763,374	761,095	758,818	757,827	756,840	748,565	746,401	744,133	741,866	739,599	737,332	9,021,509
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		765,659	763,374	761,072	758,399	757,442	756,737	748,538	746,342	744,133	741,866	739,599	737,332	9,020,493
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)		$765,659	$763,374	$761,072	$758,399	$757,442	$756,737	$748,538	$746,342	$744,133	$741,866	$739,599	$737,332	$9,020,493

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 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8% and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	
3.	Less: Accumulated Depreciation	(27,120,524)	(27,428,358)	(27,736,192)	(28,044,026)	(28,351,860)	(28,659,694)	(28,967,528)	(29,275,362)	(29,583,196)	(29,891,030)	(30,198,864)	(30,506,698)	(30,814,532)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$68,054,785	67,746,951	67,439,117	67,131,283	66,823,449	66,515,615	66,207,781	65,899,947	65,592,113	65,284,279	64,976,445	64,668,611	64,360,777	
6.	Average Net Investment		67,900,868	67,593,034	67,285,200	66,977,366	66,669,532	66,361,698	66,053,864	65,746,030	65,438,196	65,130,362	64,822,528	64,514,694	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		397,633	395,830	394,028	392,225	390,422	388,620	385,534	383,738	381,941	380,144	378,347	376,551	$4,645,013
	b. Debt Component Grossed Up For Taxes (C)		107,204	106,718	106,232	105,746	105,260	104,774	98,855	98,394	97,934	97,473	97,012	96,552	1,222,154
8.	Investment Expenses														
	a. Depreciation (D)		$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	3,694,008
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		812,671	810,382	808,094	805,805	803,516	801,228	792,223	789,966	787,709	785,451	783,193	780,937	9,561,175
	a. Recoverable Costs Allocated to Energy		812,671	810,382	808,094	805,805	803,516	801,228	792,223	789,966	787,709	785,451	783,193	780,937	9,561,175
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		812,671	810,382	808,069	805,360	803,108	801,119	792,195	789,904	787,709	785,451	783,193	780,937	9,560,098
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)		$812,671	$810,382	$808,069	$805,360	$803,108	$801,119	$792,195	$789,904	$787,709	$785,451	$783,193	$780,937	$9,560,098

Notes:

(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($53,093,397), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20180007-EI
ECRC 2017 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 19 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

Form 42-8A

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		$8,218	$40,313	$119,276	$44,067	$39,007	($80,025)	$0	$0	$0	$0	$0	$0	$170,856
	b. Clearings to Plant		0	0	1,391,667	44,067	39,007	(80,025)	0	0	0	0	0	0	1,394,715.87
	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)	$80,369,887	$80,369,887	$80,369,887	$81,761,553	$81,805,620	$81,844,627	$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	(24,927,025)	(25,174,566)	(25,422,107)	(25,669,648)	(25,921,712)	(26,173,919)	(26,426,253)	(26,678,327)	(26,930,401)	(27,182,475)	(27,434,549)	(27,686,623)	(27,938,697)	
4.	CWIP - Non-Interest Bearing	1,223,860	1,232,077	1,272,390	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5.	Net Investment (Lines 2 + 3 + 4)	$56,666,721	56,427,398	56,220,170	56,091,905	55,883,908	55,670,708	55,338,349	55,086,275	54,834,201	54,582,127	54,330,053	54,077,979	53,825,905	
6.	Average Net Investment		56,547,060	56,323,784	56,156,037	55,987,906	55,777,308	55,504,528	55,212,312	54,960,238	54,708,164	54,456,090	54,204,016	53,951,942	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		331,144	329,837	328,854	327,870	326,637	325,039	322,256	320,785	319,313	317,842	316,371	314,900	$3,880,848
	b. Debt Component Grossed Up For Taxes (C)		89,278	88,926	88,661	88,396	88,063	87,632	82,630	82,253	81,875	81,498	81,121	80,744	1,021,077
8.	Investment Expenses														
	a. Depreciation (D)		$247,541	$247,541	$247,541	$252,064	$252,207	$252,334	$252,074	$252,074	$252,074	$252,074	$252,074	$252,074	3,011,672
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		667,963	666,304	665,056	668,330	666,907	665,005	656,960	655,112	653,262	651,414	649,566	647,718	7,913,597
	a. Recoverable Costs Allocated to Energy		667,963	666,304	665,056	668,330	666,907	665,005	656,960	655,112	653,262	651,414	649,566	647,718	7,913,597
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		667,963	666,304	665,036	667,961	666,568	664,914	656,937	655,061	653,262	651,414	649,566	647,718	7,912,704
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$667,963	$666,304	$665,036	$667,961	$666,568	$664,914	$656,937	$655,061	$653,262	$651,414	$649,566	$647,718	$7,912,704

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 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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

DOCKET NO. 20180007-EI
ECRC 2017 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 20 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$65,312,615	$65,312,615	$65,312,615	$65,312,615	$65,312,615	$65,312,615	$65,312,615	$65,312,615	$65,312,615	$65,312,615	$65,312,615	$65,312,615	$65,312,615	
3.	Less: Accumulated Depreciation	(20,261,253)	(20,448,963)	(20,636,673)	(20,824,383)	(21,012,093)	(21,199,803)	(21,387,513)	(21,575,223)	(21,762,933)	(21,950,643)	(22,138,353)	(22,326,063)	(22,513,773)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$45,051,362	44,863,652	44,675,942	44,488,232	44,300,522	44,112,812	43,925,102	43,737,392	43,549,682	43,361,972	43,174,262	42,986,552	42,798,842	
6.	Average Net Investment		44,957,507	44,769,797	44,582,087	44,394,377	44,206,667	44,018,957	43,831,247	43,643,537	43,455,827	43,268,117	43,080,407	42,892,697	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		263,275	262,176	261,076	259,977	258,878	257,779	255,828	254,733	253,637	252,542	251,446	250,350	$3,081,697
	b. Debt Component Grossed Up For Taxes (C)		70,980	70,684	70,388	70,091	69,795	69,499	65,597	65,316	65,035	64,754	64,473	64,192	810,804
8.	Investment Expenses														
	a. Depreciation (D)		$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	2,252,520
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		521,965	520,570	519,174	517,778	516,383	514,988	509,135	507,759	506,382	505,006	503,629	502,252	6,145,021
	a. Recoverable Costs Allocated to Energy		521,965	520,570	519,174	517,778	516,383	514,988	509,135	507,759	506,382	505,006	503,629	502,252	6,145,021
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		521,965	520,570	519,158	517,492	516,121	514,918	509,117	507,719	506,382	505,006	503,629	502,252	6,144,329
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)		$521,965	$520,570	$519,158	$517,492	$516,121	$514,918	$509,117	$507,719	$506,382	$505,006	$503,629	$502,252	$6,144,329

Notes:

(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($36,567,266), 315.54 ($10,642,027), 316.54 ($687,934), and 315.40 ($558,138)
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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

DOCKET NO. 20180007-EI
ECRC 2017 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 2017 to December 2017

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		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	a. Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Clearings to Plant		0	0	0	0	0	0	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	
2.	Plant-in-Service/Depreciation Base (A)	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	
3.	Less: Accumulated Depreciation	(3,984,954)	(4,036,263)	(4,087,572)	(4,138,881)	(4,190,190)	(4,241,499)	(4,292,808)	(4,344,117)	(4,395,426)	(4,446,735)	(4,498,044)	(4,549,353)	(4,600,662)	
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)	$20,351,753	20,300,444	20,249,135	20,197,826	20,146,517	20,095,208	20,043,899	19,992,590	19,941,281	19,889,972	19,838,663	19,787,354	19,736,045	
6.	Average Net Investment		20,326,099	20,274,790	20,223,481	20,172,172	20,120,863	20,069,554	20,018,245	19,966,936	19,915,627	19,864,318	19,813,009	19,761,700	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		119,031	118,731	118,430	118,130	117,829	117,529	116,840	116,540	116,241	115,941	115,642	115,342	$1,406,226
	b. Debt Component Grossed Up For Taxes (C)		32,092	32,011	31,930	31,848	31,767	31,686	29,959	29,882	29,805	29,729	29,652	29,575	369,936
8.	Investment Expenses														
	a. Depreciation (D)		$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	615,708
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		202,432	202,051	201,669	201,287	200,905	200,524	198,108	197,731	197,355	196,979	196,603	196,226	2,391,870
	a. Recoverable Costs Allocated to Energy		202,432	202,051	201,669	201,287	200,905	200,524	198,108	197,731	197,355	196,979	196,603	196,226	2,391,870
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		202,432	202,051	201,663	201,176	200,803	200,497	198,101	197,715	197,355	196,979	196,603	196,226	2,391,601
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)		$202,432	$202,051	$201,663	$201,176	$200,803	$200,497	$198,101	$197,715	$197,355	$196,979	$196,603	$196,226	$2,391,601

Notes:

(A) Applicable depreciable base for Big Bend; account 312.45 ($22,880,499) and 312.44 ($1,456,209).
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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

DOCKET NO. 20180007-EI
ECRC 2017 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 2017 to December 2017

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	8,586,395	8,586,395	8,586,395	8,586,395	8,586,395	8,586,395	8,586,395	8,586,395	8,586,395	8,586,395	8,586,395	8,586,395	8,586,395	
3.	Less: Accumulated Depreciation	(893,172)	(915,051)	(936,930)	(958,809)	(980,688)	(1,002,567)	(1,024,446)	(1,046,325)	(1,068,204)	(1,090,083)	(1,111,962)	(1,133,841)	(1,155,720)	
4.	CWIP - Non-Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
5.	Net Investment (Lines 2 + 3 + 4)	$7,693,223	7,671,344	7,649,465	7,627,586	7,605,707	7,583,828	7,561,949	7,540,070	7,518,191	7,496,312	7,474,433	7,452,554	7,430,675	
6.	Average Net Investment		7,682,284	7,660,405	7,638,526	7,616,647	7,594,768	7,572,889	7,551,010	7,529,131	7,507,252	7,485,373	7,463,494	7,441,615	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		44,988	44,860	44,732	44,604	44,476	44,347	44,073	43,945	43,817	43,690	43,562	43,434	$530,528
	b. Debt Component Grossed Up For Taxes (C)		12,129	12,095	12,060	12,025	11,991	11,956	11,301	11,268	11,235	11,202	11,170	11,137	139,569
8.	Investment Expenses														
	a. Depreciation (D)		21,879	21,879	21,879	21,879	21,879	21,879	21,879	21,879	21,879	21,879	21,879	21,879	262,548
	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)		78,996	78,834	78,671	78,508	78,346	78,182	77,253	77,092	76,931	76,771	76,611	76,450	932,645
	a. Recoverable Costs Allocated to Energy		78,996	78,834	78,671	78,508	78,346	78,182	77,253	77,092	76,931	76,771	76,611	76,450	932,645
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		78,996	78,834	78,669	78,465	78,306	78,171	77,250	77,086	76,931	76,771	76,611	76,450	932,540
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)		$78,996	$78,834	$78,669	$78,465	$78,306	$78,171	$77,250	$77,086	$76,931	$76,771	$76,611	$76,450	$932,540

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 ($50,704), 311.40 ($13,216), 345.81 ($2,232), and 312.54 ($210,295)

(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)

(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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%, and 3.8%

(E) Line 9a x Line 10

(F) Line 9b x Line 11

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ECRC 2017 FINAL TRUE-UP
EXHIBIT PAR-1, DOC. NO. 8, PAGE 23 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of Final True-up Amount for the Period
January 2017 to December 2017

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	95	0	0	0	0	0	0	0	0	95
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	(34,829)	(34,734)	(34,734)	(34,734)	(34,654)	(34,654)	(34,654)	(34,570)	(34,570)	(34,570)	(34,513)	(34,513)	(34,513)	
3.	Total Working Capital Balance	($34,829)	(34,734)	(34,734)	(34,734)	(34,654)	(34,654)	(34,654)	(34,570)	(34,570)	(34,570)	(34,513)	(34,513)	(34,513)	
4.	Average Net Working Capital Balance		($34,781)	($34,734)	($34,734)	($34,694)	($34,654)	($34,654)	($34,612)	($34,570)	($34,570)	($34,542)	($34,513)	($34,513)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(204)	(203)	(203)	(203)	(203)	(203)	(202)	(202)	(202)	(202)	(201)	(201)	(2,429)
	b. Debt Component Grossed Up For Taxes (B)		(55)	(55)	(55)	(55)	(55)	(55)	(52)	(52)	(52)	(52)	(52)	(52)	(642)
6.	Total Return Component		(259)	(258)	(258)	(258)	(258)	(258)	(254)	(254)	(254)	(254)	(253)	(253)	(3,071)
7.	Expenses:														
	a. Gains		0	0	0	(95)	0	0	0	0	0	0	0	0	(95)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(75)	3	15	(72)	9	6	(74)	3	2	(34)	17	18	(182)
8.	Net Expenses (D)		(75)	3	15	(167)	9	6	(74)	3	2	(34)	17	18	(277)
9.	Total System Recoverable Expenses (Lines 6 + 8)		(334)	(255)	(243)	(425)	(249)	(252)	(328)	(251)	(252)	(288)	(236)	(235)	(3,348)
	a. Recoverable Costs Allocated to Energy		(334)	(255)	(243)	(425)	(249)	(252)	(328)	(251)	(252)	(288)	(236)	(235)	(3,348)
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		(334)	(255)	(243)	(424)	(249)	(252)	(328)	(251)	(252)	(288)	(236)	(235)	(3,347)
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)		($334)	($255)	($243)	($424)	($249)	($252)	($328)	($251)	($252)	($288)	($236)	($235)	($3,347)

Notes:
(A) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(B) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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

* 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 2017 to December 2017

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$222.80	$519.59	$0.00	$3,082.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3,825
	b. Clearings to Plant		222.80	519.59	0.00	3,082.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3,825
	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)	21,463,534	21,463,757	21,464,276	21,464,276	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	21,467,359	
3.	Less: Accumulated Depreciation	(1,287,262)	(1,339,132)	(1,391,003)	(1,442,875)	(1,494,747)	(1,546,626)	(1,598,505)	(1,650,384)	(1,702,263)	(1,754,142)	(1,806,021)	(1,857,900)	(1,909,779)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$20,176,272	20,124,625	20,073,273	20,021,401	19,972,612	19,920,733	19,868,854	19,816,975	19,765,096	19,713,217	19,661,338	19,609,459	19,557,580	
6.	Average Net Investment		20,150,448	20,098,949	20,047,337	19,997,007	19,946,673	19,894,794	19,842,915	19,791,036	19,739,157	19,687,278	19,635,399	19,583,520	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		118,003	117,701	117,399	117,104	116,809	116,506	115,816	115,514	115,211	114,908	114,605	114,302	$1,393,878
	b. Debt Component Grossed Up For Taxes (C)		31,814	31,733	31,651	31,572	31,492	31,411	29,697	29,619	29,541	29,464	29,386	29,308	366,688
8.	Investment Expenses														
	a. Depreciation (D)		51,870	51,871	51,872	51,872	51,879	51,879	51,879	51,879	51,879	51,879	51,879	51,879	622,517
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		201,687	201,305	200,922	200,548	200,180	199,796	197,392	197,012	196,631	196,251	195,870	195,489	2,383,083
	a. Recoverable Costs Allocated to Energy		201,687	201,305	200,922	200,548	200,180	199,796	197,392	197,012	196,631	196,251	195,870	195,489	2,383,083
	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	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		201,687	201,305	200,916	200,437	200,078	199,769	197,385	196,997	196,631	196,251	195,870	195,489	2,382,815
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)		$201,687	$201,305	$200,916	$200,437	$200,078	$199,769	$197,385	$196,997	$196,631	$196,251	$195,870	$195,489	$2,382,815

Notes:

(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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 2017 to December 2017

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Coal Combustion Residuals Rule
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$38,897	$73,061	$134,967	$213,581	$41,422	$37,847	$25,027	$38,771	$13,597	$3,734	$23,551	$75,634	$720,089
	b. Clearings to Plant		0	0	0	0	0	0	581,820	70,453	13,782	3,734	(1,054)	0	668,735
	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)	-	-	-	-	-	-	-	581,820	652,273	666,055	669,789	668,735	668,735	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	(1,455)	(3,086)	(4,751)	(6,425)	(8,097)	
4.	CWIP - Non-Interest Bearing	48,885	87,783	160,843	295,810	509,391	550,813	588,660	31,867	185	(0)	(0)	24,605	100,239	
5.	Net Investment (Lines 2 + 3 + 4)	$48,885	87,783	160,843	295,810	509,391	550,813	588,660	613,687	651,003	662,969	665,038	686,915	760,877	
6.	Average Net Investment		68,334	124,313	228,327	402,601	530,102	569,737	601,174	632,345	656,986	664,003	675,976	723,896	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		400	728	1,337	2,358	3,104	3,336	3,509	3,691	3,835	3,876	3,945	4,225	$34,344
	b. Debt Component Grossed Up For Taxes (C)		108	196	360	636	837	900	900	946	983	994	1,012	1,083	8,955
8.	Investment Expenses														
	a. Depreciation (D)		-	-	-	-	-	-	-	1,455	1,631	1,665	1,674	1,672	8,097
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		508	924	1,697	2,994	3,941	4,236	4,409	6,092	6,449	6,535	6,631	6,980	51,396
	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		508	924	1,697	2,994	3,941	4,236	4,409	6,092	6,449	6,535	6,631	6,980	51,396
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	0.9999695	0.9994472	0.9994922	0.9998635	0.9999645	0.9999215	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	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)		506	920	1,690	2,982	3,925	4,219	4,391	6,067	6,449	6,535	6,631	6,980	51,294
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$506	$920	$1,690	$2,982	$3,925	$4,219	$4,391	$6,067	$6,449	$6,535	$6,631	$6,980	$51,294

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.44
(B) Line 6 x 7.0273% x 1/12 (Jan-Jun) and Line 6 x 7.0040% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 38.575% (expansion factor of 1.632200)
(C) Line 6 x 1.8946% x 1/12 (Jan-Jun) and Line 6 x 1.7959% 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 Form 42 - 9A
Environmental Cost Recovery Clause (ECRC) Page 1 of 2
Calculation of Final True-up Amount for the Period
January 2017 to June 2017

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base **Actual May 2016**	(2) Ratio	(3) Cost Rate	(4) Weighted Cost Rate
	($000)	%	%	%
Long Term Debt	$ 1,548,383	35.17%	5.17%	1.8200%
Short Term Debt	25,435	0.58%	0.90%	0.0100%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	106,847	2.43%	2.29%	0.0600%
Common Equity	1,847,526	41.96%	10.25%	4.3000%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	866,653	19.69%	0.00%	0.0000%
Deferred ITC - Weighted Cost	7,686	0.17%	7.89%	0.0100%
Total	$ 4,402,530	100.00%		6.20%

ITC split between Debt and Equity:

Long Term Debt	$ 1,548,383	Long Term Debt	45.26%
Short Term Debt	25,435	Short Term Debt	0.74%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,847,526	Equity - Common	54.00%
Total	$ 3,421,345	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0100% * 46.00%	0.0046%
Equity = .0100% * 54.00%	0.0054%
Weighted Cost	0.0100%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3000%
Deferred ITC - Weighted Cost	0.0054%
	4.3054%
Times Tax Multiplier	1.632200
Total Equity Component	7.0273%

Total Debt Cost Rate:

Long Term Debt	1.8200%
Short Term Debt	0.0100%
Customer Deposits	0.0600%
Deferred ITC - Weighted Cost	0.0046%
Total Debt Component	1.8946%
	8.9219%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (4) - Column (2) x Column (3)

Tampa Electric Company Form 42 - 9A
Environmental Cost Recovery Clause (ECRC) Page 2 of 2
Calculation of the Final True-up Amount for the Period
JULY 2017 to DECEMBER 2017

Calculation of Revenue Requirement Rate of Return
(In Dollars)

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

ITC split between Debt and Equity:

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

Deferred ITC - Weighted Cost:

Debt = .0100% * 46.00%	0.0082%
Equity = .0100% * 54.00%	0.0097%
Weighted Cost	0.0179%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.2815%
Deferred ITC - Weighted Cost	0.0097%
	4.2912%
Times Tax Multiplier	1.632200
Total Equity Component	7.0040%

Total Debt Cost Rate:

Long Term Debt	1.6968%
Short Term Debt	0.0378%
Customer Deposits	0.0531%
Deferred ITC - Weighted Cost	0.0082%
Total Debt Component	1.7959%
	8.7999%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (4) - Column (2) x Column (3)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 27
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-2

INDEX

TAMPA ELECTRIC COMPANY

ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL/ESTIMATED TRUE-UP AMOUNT

FOR THE PERIOD

JANUARY 2018 THROUGH DECEMBER 2018

FORMS 42-1E THROUGH 42-9E

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Tampa Electric Company

Form 42 - 1E

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

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$13,260,224
2.	Interest Provision (Form 42-2E, Line 6)	212,259
3.	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4.	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2019 to December 2019 (Lines 1 + 2 + 3)	$13,472,483

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

Form 42 - 2E

Current Period True-Up Amount
(in Dollars)

Line	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1. ECRC Revenues (net of Revenue Taxes)	$5,299,826	$4,794,184	$4,754,839	$4,804,461	$5,074,853	$5,873,006	$6,540,375	$6,493,000	$6,689,809	$5,928,024	$4,939,446	$4,863,661	$66,055,485
2. True-Up Provision	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,449	6,101,344
3. ECRC Revenues Applicable to Period (Lines 1 + 2) [1]	5,808,271	5,302,629	5,263,284	5,312,906	5,583,298	6,381,451	7,048,820	7,001,445	7,198,254	6,436,469	5,447,891	5,372,110	72,156,829
4. Jurisdictional ECRC Costs													
a. O & M Activities (Form 42-5E, Line 9)	1,874,870	2,166,060	1,373,137	959,540	1,185,543	743,043	405,177	403,175	395,441	910,226	1,021,725	1,269,328	12,707,265
b. Capital Investment Projects (Form 42-7E, Line 9)	3,891,399	3,881,399	3,871,500	3,861,963	3,853,761	3,845,686	3,837,559	3,832,715	3,832,592	3,832,139	3,826,917	3,821,709	46,189,339
c. Total Jurisdictional ECRC Costs	5,766,269	6,047,459	5,244,637	4,821,503	5,039,304	4,588,729	4,242,736	4,235,890	4,228,033	4,742,365	4,848,642	5,091,037	58,896,604
5. Over/Under Recovery (Line 3 - Line 4c) [1]	42,002.00	(744,830)	18,647	491,403	543,994.00	1,792,722.00	2,806,084.00	2,765,555.00	2,970,221.00	1,694,104.00	599,249.00	281,073	13,260,224
6. Interest Provision (Form 42-3E, Line 10)	9,356	8,341	8,197	8,382	8,410	9,750	14,605	20,780	25,636	30,995	33,942	33,865	212,259
7. Beginning Balance True-Up & Interest Provision [1]	6,101,344	5,644,257	4,399,323	3,917,722	3,909,062	3,953,021	5,247,048	7,559,292	9,837,182	12,324,594	13,541,248	13,665,994	6,101,344
a. Deferred True-Up from January to December 2018 (Order No. PSC-2018-0014-FOF-EI)	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666
8. True-Up Collected/(Refunded) (see Line 2)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,449)	(6,101,344)
9. End of Period Total True-Up (Lines 5+6+7+7a+8) [1]	7,142,923	5,897,989	5,416,388	5,407,728	5,451,687	6,745,714	9,057,958	11,335,848	13,823,260	15,039,914	15,164,660	14,971,149	14,971,149
10. Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11. End of Period Total True-Up (Lines 9 + 10) [1]	$7,142,923	$5,897,989	$5,416,388	$5,407,728	$5,451,687	$6,745,714	$9,057,958	$11,335,848	$13,823,260	$15,039,914	$15,164,660	$14,971,149	$14,971,149

DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. PAR-2, DOCUMENT NO. 2, PAGE 1 OF 1
REVISED: 7/27/2018

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

Form 42 - 3E

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	$7,600,010	$7,142,923	$5,897,989	$5,416,388	$5,407,728	$5,451,687	$6,745,714	$9,057,958	$11,335,848	$13,823,260	$15,039,914	$15,164,660	
2.	Ending True-Up Amount Before Interest	7,133,567	5,889,648	5,408,191	5,399,346	5,443,277	6,735,964	9,043,353	11,315,068	13,797,624	15,008,919	15,130,718	14,937,284	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2) [1]	14,733,577	13,032,571	11,306,180	10,815,734	10,851,005	12,187,651	15,789,067	20,373,026	25,133,472	28,832,179	30,170,632	30,101,944	
4.	Average True-Up Amount (Line 3 x 1/2) [1]	7,366,789	6,516,286	5,653,090	5,407,867	5,425,503	6,093,826	7,894,534	10,186,513	12,566,736	14,416,090	15,085,316	15,050,972	
5.	Interest Rate (First Day of Reporting Business Month)	1.58%	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	2.45%	2.45%	2.45%	2.70%	2.70%	
6.	Interest Rate (First Day of Subsequent Business Month)	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	2.45%	2.45%	2.45%	2.70%	2.70%	2.70%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6) [1]	3.04%	3.08%	3.48%	3.71%	3.71%	3.84%	4.43%	4.90%	4.90%	5.15%	5.40%	5.40%	
8.	Average Interest Rate (Line 7 x 1/2) [1]	1.520%	1.540%	1.740%	1.855%	1.855%	1.920%	2.215%	2.450%	2.450%	2.575%	2.700%	2.700%	
9.	Monthly Average Interest Rate (Line 8 x 1/12) [1]	0.127%	0.128%	0.145%	0.155%	0.155%	0.160%	0.185%	0.204%	0.204%	0.215%	0.225%	0.225%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$9,356	$8,341	$8,197	$8,382	$8,410	$9,750	$14,605	$20,780	$25,636	$30,995	$33,942	$33,865	$212,259

DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
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REVISED: 7/27/2018

Tampa Electric Company Form 42 - 4E

Environmental Cost Recovery Clause

Calculation of the Current Period Actual / Estimated Amount

January 2018 to December 2018

Variance Report of O & M Activities

(In Dollars)

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

Notes:

Column (1) is the End of Period Totals on Form 42-5E.

Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2018-0014-FOF-EI.

Column (3) = Column (1) - Column (2)

Column (4) = Column (3) / Column (2)

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

Form 42 - 5E

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 FGD Integration	452,214	273,733	291,066	358,824	331,130	187,714	0	0	0	0	0	0	1,894,681		$1,894,681
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(34)	5	8	(16)	22	(83)	0	0	0	0	0	0	(98)		(98)
	d. Big Bend Units 1 & 2 FGD	17,413	66,376	55,024	54,100	100,066	19,825	43,000	43,000	43,000	43,000	43,000	43,000	570,804		570,804
	e. Big Bend PM Minimization and Monitoring	52,762	44,712	67,899	54,273	45,912	27,938	15,000	15,000	8,065	25,000	25,000	25,000	406,562		406,562
	f. Big Bend NO_x Emissions Reduction	37	34,122	266	2,757	78	29,434	2,000	2,000	2,000	2,000	2,000	2,000	78,693		78,693
	g. NPDES Annual Surveillance Fees	34,500	0	0	0	0	1,383	0	0	0	0	0	0	35,883	$35,883	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	i. Polk NO_x Emissions Reduction	688	853	440	0	0	35	950	950	400	0	250	750	5,317		5,317
	j. Bayside SCR and Ammonia	16,454	3,210	8,560	12,325	3,210	11,843	12,500	10,000	9,000	8,000	8,000	8,000	111,102		111,102
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	0	0	39	0	0	0	0	0	0	0	0	0	39		39
	m. Big Bend Unit 2 Pre-SCR	635	0	0	815	0	0	0	0	0	0	0	0	1,450		1,450
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	3,714	94	0	0	0	0	0	0	3,808		3,808
	o. Clean Water Act Section 316(b) Phase II Study	4,499	14,303	174	21,348	75	9	0	1,250	1,250	1,250	12,500	17,500	74,158	74,158	
	p. Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	q. Big Bend 1 SCR	6,777	18,340	3,087	32,717	33,063	14,694	40,801	41,277	39,690	50,168	24,607	45,881	351,102		351,102
	r. Big Bend 2 SCR	4,267	6,863	6,549	54,763	9,514	7,682	45,405	45,722	47,627	60,328	24,607	47,786	361,113		361,113
	s. Big Bend 3 SCR	125,936	154,048	270,635	166,420	280,869	192,408	60,405	60,722	62,627	33,098	83,425	62,791	1,553,384		1,553,384
	t. Big Bend 4 SCR	58,197	89,093	46,317	54,593	33,834	55,218	51,866	50,754	48,532	54,882	65,836	42,023	651,145		651,145
	u. Mercury Air Toxics Standards	0	0	7,823	55	0	0	3,250	2,500	3,250	2,500	2,500	2,500	24,378		24,378
	v. Greenhouse Gas Reduction Program	2,825	0	0	0	93,149	0	0	0	0	0	0	0	95,974		95,974
	w. Big Bend Gypsum Storage Facility (East 40)	163,867	110,837	59,289	124,795	239,532	159,952	130,000	130,000	130,000	130,000	130,000	130,000	1,638,273		1,638,273
	x. CCR Rule - Phase I	(3,500)	14,103	14,033	1,844	9,875	1,895	0	0	0	0	0	0	38,250		38,250
	y. Big Bend ELG Rule Study	0	11,472	0	9,832	0	32,703	0	0	0	0	0	0	54,007		54,007
	z. CCR Rule - Phase II	937,333	1,323,990	541,927	10,095	1,500	297	0	0	0	500,000	600,000	842,097	4,757,238		4,757,238
	aa. BB Unit 1 Section 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	ab. Big Bend ELG Rule Compliance	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	1,874,870	2,166,060	1,373,137	959,540	1,185,543	743,043	405,177	403,175	395,441	910,226	1,021,725	1,269,328	12,707,265	$110,042	$12,597,223
3.	Recoverable Costs Allocated to Energy	1,835,871	2,151,757	1,372,963	938,192	1,185,468	741,650	405,177	401,925	394,191	908,976	1,009,225	1,251,828	12,597,223		
4.	Recoverable Costs Allocated to Demand	38,999	14,303	174	21,348	75	1,393	0	1,250	1,250	1,250	12,500	17,500	110,042		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (A)	1,835,871	2,151,757	1,372,963	938,192	1,185,468	741,650	405,177	401,925	394,191	908,976	1,009,225	1,251,828	12,597,223		
8.	Jurisdictional Demand Recoverable Costs (B)	38,999	14,303	174	21,348	75	1,393	0	1,250	1,250	1,250	12,500	17,500	110,042		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,874,870	$2,166,060	$1,373,137	$959,540	$1,185,543	$743,043	$405,177	$403,175	395,441	910,226	$1,021,725	$1,269,328	$12,707,265		

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REVISED: 7/27/2018

Tampa Electric Company Form 42 - 6E

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

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

Line		(1) Actual / Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 FGD Integration	$960,463	$1,063,216	($102,753)	-9.7%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	249,611	280,951	(31,340)	-11.2%
	c. Big Bend Unit 4 Continuous Emissions Monitors	51,105	55,016	(3,911)	-7.1%
	d. Big Bend Fuel Oil Tank No. 1 Upgrade	55,001	35,856	19,145	53.4%
	e. Big Bend Fuel Oil Tank No. 2 Upgrade	90,462	58,969	31,493	53.4%
	f. Big Bend Unit 1 Classifier Replacement	80,406	85,047	(4,641)	-5.5%
	g. Big Bend Unit 2 Classifier Replacement	58,125	61,751	(3,626)	-5.9%
	h. Big Bend Section 114 Mercury Testing Platform	8,562	9,406	(844)	-9.0%
	i. Big Bend Units 1 & 2 FGD	6,053,894	6,674,906	(621,012)	-9.3%
	j. Big Bend FGD Optimization and Utilization	1,554,567	1,712,875	(158,308)	-9.2%
	k. Big Bend NO_x Emissions Reduction	499,286	562,354	(63,068)	-11.2%
	l. Big Bend PM Minimization and Monitoring	1,809,209	1,989,614	(180,405)	-9.1%
	m. Polk NO_x Emissions Reduction	113,289	123,356	(10,067)	-8.2%
	n. Big Bend Unit 4 SOFA	198,213	218,523	(20,310)	-9.3%
	o. Big Bend Unit 1 Pre-SCR	137,625	149,608	(11,983)	-8.0%
	p. Big Bend Unit 2 Pre-SCR	130,774	142,854	(12,080)	-8.5%
	q. Big Bend Unit 3 Pre-SCR	233,143	256,173	(23,030)	-9.0%
	r. Big Bend Unit 1 SCR	7,960,376	8,698,396	(738,020)	-8.5%
	s. Big Bend Unit 2 SCR	8,407,010	9,195,158	(788,148)	-8.6%
	t. Big Bend Unit 3 SCR	6,968,871	7,628,421	(659,550)	-8.6%
	u. Big Bend Unit 4 SCR	5,420,387	5,919,666	(499,279)	-8.4%
	v. Big Bend FGD System Reliability	2,080,400	2,325,371	(244,971)	-10.5%
	w. Mercury Air Toxics Standards	824,496	928,320	(103,824)	-11.2%
	x. SO_2 Emissions Allowances	(2,601)	(3,015)	414	-13.7%
	y. Big Bend Gypsum Storage Facility	2,073,526	2,316,204	(242,678)	-10.5%
	z. CCR Rule - Phase I	130,502	224,233	(93,731)	-41.8%
	aa. CCR Rule - Phase II	2,299	0	2,299	N/A
	ab. Big Bend ELG Rule Compliance	1,411	0	1,411	N/A
	ac. Big Bend Unit 1 Section 316(b) Impingement Mortality	38,927	0	38,927	N/A
2.	Total Investment Projects - Recoverable Costs	$46,189,339	$50,713,229	($4,523,890)	-8.9%
3.	Recoverable Costs Allocated to Energy	$45,870,737	$50,394,171	($4,523,434)	-9.0%
4.	Recoverable Costs Allocated to Demand	$318,602	$319,058	($456)	-0.1%

Notes:

Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2018-0014-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description (A)	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1. a.	Big Bend Unit 3 FGD Integration	$81,171	$80,989	$80,808	$80,626	$80,445	$80,262	$79,812	$79,632	$79,450	$79,270	$79,089	$78,909	$960,463		$960,463
b.	Big Bend Units 1 and 2 Flue Gas Conditioning	21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611		249,611
c.	Big Bend Unit 4 Continuous Emissions Monitors	4,344	4,330	4,314	4,300	4,285	4,271	4,247	4,232	4,217	4,203	4,188	4,174	51,105		51,105
d.	Big Bend Fuel Oil Tank No. 1 Upgrade	2,815	2,806	2,796	2,787	2,778	2,770	6,455	6,423	6,391	6,359	6,326	6,295	55,001	$55,001	
e.	Big Bend Fuel Oil Tank No. 2 Upgrade	4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,565	10,512	10,458	10,405	10,353	90,462	90,462	
f.	Big Bend Unit 1 Classifier Replacement	6,859	6,830	6,803	6,775	6,748	6,720	6,681	6,653	6,625	6,598	6,571	6,543	80,406		80,406
g.	Big Bend Unit 2 Classifier Replacement	4,954	4,934	4,915	4,896	4,877	4,858	4,829	4,811	4,791	4,772	4,754	4,734	58,125		58,125
h.	Big Bend Section 114 Mercury Testing Platform	725	722	721	719	717	716	712	709	708	706	704	703	8,562		8,562
i.	Big Bend Units 1 & 2 FGD	514,191	512,541	510,891	509,241	507,592	505,942	503,019	501,378	499,737	498,095	496,454	494,813	6,053,894		6,053,894
j.	Big Bend FGD Optimization and Utilization	126,787	126,722	126,673	127,106	128,669	130,581	130,375	130,539	130,969	131,509	132,049	132,588	1,554,567		1,554,567
k.	Big Bend NO_x Emissions Reduction	42,042	41,978	41,914	41,850	41,785	41,721	41,493	41,428	41,364	41,301	41,237	41,173	499,286		499,286
l.	Big Bend PM Minimization and Monitoring	153,110	152,726	152,343	151,960	151,576	151,193	150,337	149,956	149,574	149,193	148,811	148,430	1,809,209		1,809,209
m.	Polk NO_x Emissions Reduction	9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,385	9,358	9,331	9,302	9,275	113,289		113,289
n.	Big Bend Unit 4 SOFA	16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,350	16,310	16,270	198,213		198,213
o.	Big Bend Unit 1 Pre-SCR	11,675	11,640	11,605	11,571	11,536	11,502	11,435	11,401	11,366	11,332	11,298	11,264	137,625		137,625
p.	Big Bend Unit 2 Pre-SCR	11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774		130,774
q.	Big Bend Unit 3 Pre-SCR	19,734	19,684	19,634	19,583	19,533	19,484	19,373	19,324	19,273	19,224	19,173	19,124	233,143		233,143
r.	Big Bend Unit 1 SCR	674,992	673,045	671,098	669,150	667,203	665,256	661,449	659,511	657,574	655,636	653,700	651,762	7,960,376		7,960,376
s.	Big Bend Unit 2 SCR	712,268	710,328	708,390	706,451	704,511	702,572	698,570	696,642	694,713	692,784	690,855	688,926	8,407,010		8,407,010
t.	Big Bend Unit 3 SCR	590,325	588,737	587,150	585,562	583,973	582,386	579,071	577,492	575,913	574,333	572,754	571,175	6,968,871		6,968,871
u.	Big Bend Unit 4 SCR	456,706	455,523	454,342	453,169	452,014	450,873	449,747	449,981	450,214	450,449	449,273	448,096	5,420,387		5,420,387
v.	Big Bend FGD System Reliability	175,463	175,139	174,817	174,494	174,170	173,847	172,882	172,560	172,239	171,918	171,597	171,274	2,080,400		2,080,400
w.	Mercury Air Toxics Standards	68,615	68,478	68,407	68,337	68,454	68,315	67,997	67,921	68,879	69,836	69,698	69,559	824,496		824,496
x.	SO_2 Emissions Allowances (B)	(218)	(218)	(218)	(217)	(217)	(217)	(216)	(216)	(216)	(216)	(216)	(216)	(2,601)		(2,601)
y.	Big Bend Gypsum Storage Facility	174,907	174,580	174,253	173,927	173,600	173,274	172,310	171,985	171,660	171,335	171,010	170,685	2,073,526		2,073,526
z.	CCR Rule - Phase I	6,478	6,646	6,816	6,860	6,907	6,960	8,554	10,575	14,687	17,887	18,670	19,462	130,502	130,502	
aa.	CCR Rule - Phase II	0	0	3	7	11	21	86	202	319	434	550	666	2,299	2,299	
ab.	Big Bend ELG Rule Compliance	0	0	0	0	0	0	0	0	0	157	470	784	1,411	1,411	
ac.	Big Bend Unit 1 Section 316(b) Impingement Mortality	0	0	0	0	0	0	235	1,723	4,543	7,676	10,808	13,942	38,927	38,927	
2.	Total Investment Projects - Recoverable Costs	3,891,399	3,881,399	3,871,500	3,861,963	3,853,761	3,845,686	3,837,559	3,832,715	3,832,592	3,832,139	3,826,917	3,821,709	46,189,339	$318,602	$45,870,737
3.	Recoverable Costs Allocated to Energy	3,877,477	3,867,333	3,857,285	3,847,725	3,839,495	3,831,380	3,811,612	3,803,227	3,796,140	3,789,168	3,779,688	3,770,207	45,870,737		
4.	Recoverable Costs Allocated to Demand	13,922	14,066	14,215	14,238	14,266	14,306	25,947	29,488	36,452	42,971	47,229	51,502	318,602		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (C)	3,877,477	3,867,333	3,857,285	3,847,725	3,839,495	3,831,380	3,811,612	3,803,227	3,796,140	3,789,168	3,779,688	3,770,207	45,870,737		
8.	Jurisdictional Demand Recoverable Costs (D)	13,922	14,066	14,215	14,238	14,266	14,306	25,947	29,488	36,452	42,971	47,229	51,502	318,602		
9.	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$3,891,399	$3,881,399	$3,871,500	$3,861,963	$3,853,761	$3,845,686	$3,837,559	$3,832,715	$3,832,592	$3,832,139	$3,826,917	$3,821,709	$46,189,339		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Project's Total Return Component on Form 42-8E, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 FGD Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	
3.	Less: Accumulated Depreciation	(5,440,288)	(5,469,125)	(5,497,962)	(5,526,799)	(5,555,636)	(5,584,473)	(5,613,310)	(5,642,147)	(5,670,984)	(5,699,821)	(5,728,658)	(5,757,495)	(5,786,332)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$8,322,793	8,293,956	8,265,119	8,236,282	8,207,445	8,178,608	8,149,771	8,120,934	8,092,097	8,063,260	8,034,423	8,005,586	7,976,749	
6.	Average Net Investment		8,308,375	8,279,538	8,250,701	8,221,864	8,193,027	8,164,190	8,135,353	8,106,516	8,077,679	8,048,842	8,020,005	7,991,168	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$39,900	$39,761	$39,623	$39,484	$39,346	$39,207	$39,352	$39,213	$39,073	$38,934	$38,794	$38,655	$471,342
	b. Debt Component Grossed Up For Taxes (C)		12,434	12,391	12,348	12,305	12,262	12,218	11,623	11,582	11,540	11,499	11,458	11,417	143,077
8.	Investment Expenses														
	a. Depreciation (D)		$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$346,044
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		81,171	80,989	80,808	80,626	80,445	80,262	79,812	79,632	79,450	79,270	79,089	78,909	960,463
	a. Recoverable Costs Allocated to Energy		81,171	80,989	80,808	80,626	80,445	80,262	79,812	79,632	79,450	79,270	79,089	78,909	960,463
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		81,171	80,989	80,808	80,626	80,445	80,262	79,812	79,632	79,450	79,270	79,089	78,909	960,463
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$81,171	$80,989	$80,808	$80,626	$80,445	$80,262	$79,812	$79,632	$79,450	$79,270	$79,089	$78,909	$960,463

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775) and 315.45 ($327,307)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(4,179,278)	(4,195,419)	(4,211,560)	(4,227,701)	(4,243,842)	(4,259,983)	(4,276,124)	(4,292,265)	(4,308,406)	(4,324,547)	(4,340,688)	(4,356,829)	(4,372,970)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$838,456	822,315	806,174	790,033	773,892	757,751	741,610	725,469	709,328	693,187	677,046	660,905	644,764	
6.	Average Net Investment		830,386	814,245	798,104	781,963	765,822	749,681	733,540	717,399	701,258	685,117	668,976	652,835	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,988	$3,910	$3,833	$3,755	$3,678	$3,600	$3,548	$3,470	$3,392	$3,314	$3,236	$3,158	$42,882
	b. Debt Component Grossed Up For Taxes (C)		1,243	1,219	1,194	1,170	1,146	1,122	1,048	1,025	1,002	979	956	933	13,037
8.	Investment Expenses														
	a. Depreciation (D)		$16,141	$16,141	$16,141	$16,141	$16,141	$16,141	$16,141	$16,141	$16,141	$16,141	$16,141	$16,141	$193,692
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611
	a. Recoverable Costs Allocated to Energy		21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$21,372	$21,270	$21,168	$21,066	$20,965	$20,863	$20,737	$20,636	$20,535	$20,434	$20,333	$20,232	$249,611

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 4.0% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(542,165)	(544,475)	(546,785)	(549,095)	(551,405)	(553,715)	(556,025)	(558,335)	(560,645)	(562,955)	(565,265)	(567,575)	(569,885)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$324,046	321,736	319,426	317,116	314,806	312,496	310,186	307,876	305,566	303,256	300,946	298,636	296,326	
6.	Average Net Investment		322,891	320,581	318,271	315,961	313,651	311,341	309,031	306,721	304,411	302,101	299,791	297,481	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,551	$1,540	$1,528	$1,517	$1,506	$1,495	$1,495	$1,484	$1,472	$1,461	$1,450	$1,439	$17,938
	b. Debt Component Grossed Up For Taxes (C)		483	480	476	473	469	466	442	438	435	432	428	425	5,447
8.	Investment Expenses														
	a. Depreciation (D)		$2,310	$2,310	$2,310	$2,310	$2,310	$2,310	$2,310	$2,310	$2,310	$2,310	$2,310	$2,310	$27,720
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,344	4,330	4,314	4,300	4,285	4,271	4,247	4,232	4,217	4,203	4,188	4,174	51,105
	a. Recoverable Costs Allocated to Energy		4,344	4,330	4,314	4,300	4,285	4,271	4,247	4,232	4,217	4,203	4,188	4,174	51,105
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,344	4,330	4,314	4,300	4,285	4,271	4,247	4,232	4,217	4,203	4,188	4,174	51,105
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,344	$4,330	$4,314	$4,300	$4,285	$4,271	$4,247	$4,232	$4,217	$4,203	$4,188	$4,174	$51,105

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% 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 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank No. 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(273,952)	(275,362)	(276,772)	(278,182)	(279,592)	(281,002)	(282,412)	(287,535)	(292,658)	(297,781)	(302,904)	(308,027)	(313,150)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$223,626	222,216	220,806	219,396	217,986	216,576	215,166	210,043	204,920	199,797	194,674	189,551	184,428	
6.	Average Net Investment		222,921	221,511	220,101	218,691	217,281	215,871	212,605	207,482	202,359	197,236	192,113	186,990	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,071	$1,064	$1,057	$1,050	$1,043	$1,037	$1,028	$1,004	$979	$954	$929	$905	$12,121
	b. Debt Component Grossed Up For Taxes (C)		334	332	329	327	325	323	304	296	289	282	274	267	3,682
8.	Investment Expenses														
	a. Depreciation (D)		$1,410	$1,410	$1,410	$1,410	$1,410	$1,410	$5,123	$5,123	$5,123	$5,123	$5,123	$5,123	$39,198
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		2,815	2,806	2,796	2,787	2,778	2,770	6,455	6,423	6,391	6,359	6,326	6,295	55,001
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		2,815	2,806	2,796	2,787	2,778	2,770	6,455	6,423	6,391	6,359	6,326	6,295	55,001
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		2,815	2,806	2,796	2,787	2,778	2,770	6,455	6,423	6,391	6,359	6,326	6,295	55,001
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$2,815	$2,806	$2,796	$2,787	$2,778	$2,770	$6,455	$6,423	$6,391	$6,359	$6,326	$6,295	$55,001

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate through June 2018 was 3.4%; depreciation was accelerated to 12.36% as of July 2018.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank No. 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(450,592)	(452,911)	(455,230)	(457,549)	(459,868)	(462,187)	(464,506)	(472,932)	(481,358)	(489,784)	(498,210)	(506,636)	(515,062)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$367,809	365,490	363,171	360,852	358,533	356,214	353,895	345,469	337,043	328,617	320,191	311,765	303,339	
6.	Average Net Investment		366,650	364,331	362,012	359,693	357,374	355,055	349,682	341,256	332,830	324,404	315,978	307,552	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,761	$1,750	$1,739	$1,727	$1,716	$1,705	$1,691	$1,651	$1,610	$1,569	$1,528	$1,488	$19,935
	b. Debt Component Grossed Up For Taxes (C)		549	545	542	538	535	531	500	488	476	463	451	439	6,057
8.	Investment Expenses														
	a. Depreciation (D)		$2,319	$2,319	$2,319	$2,319	$2,319	$2,319	$8,426	$8,426	$8,426	$8,426	$8,426	$8,426	$64,470
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,565	10,512	10,458	10,405	10,353	90,462
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,565	10,512	10,458	10,405	10,353	90,462
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,565	10,512	10,458	10,405	10,353	90,462
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,629	$4,614	$4,600	$4,584	$4,570	$4,555	$10,617	$10,565	$10,512	$10,458	$10,405	$10,353	$90,462

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate through June 2018 was 3.4%; depreciation was accelerated to 12.35% as of July 2018.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(921,848)	(926,236)	(930,624)	(935,012)	(939,400)	(943,788)	(948,176)	(952,564)	(956,952)	(961,340)	(965,728)	(970,116)	(974,504)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$394,409	390,021	385,633	381,245	376,857	372,469	368,081	363,693	359,305	354,917	350,529	346,141	341,753	
6.	Average Net Investment		392,215	387,827	383,439	379,051	374,663	370,275	365,887	361,499	357,111	352,723	348,335	343,947	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,884	$1,862	$1,841	$1,820	$1,799	$1,778	$1,770	$1,749	$1,727	$1,706	$1,685	$1,664	$21,285
	b. Debt Component Grossed Up For Taxes (C)		587	580	574	567	561	554	523	516	510	504	498	491	6,465
8.	Investment Expenses														
	a. Depreciation (D)		$4,388	$4,388	$4,388	$4,388	$4,388	$4,388	$4,388	$4,388	$4,388	$4,388	$4,388	$4,388	$52,656
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,859	6,830	6,803	6,775	6,748	6,720	6,681	6,653	6,625	6,598	6,571	6,543	80,406
	a. Recoverable Costs Allocated to Energy		6,859	6,830	6,803	6,775	6,748	6,720	6,681	6,653	6,625	6,598	6,571	6,543	80,406
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		6,859	6,830	6,803	6,775	6,748	6,720	6,681	6,653	6,625	6,598	6,571	6,543	80,406
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,859	$6,830	$6,803	$6,775	$6,748	$6,720	$6,681	$6,653	$6,625	$6,598	$6,571	$6,543	$80,406

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(678,870)	(681,906)	(684,942)	(687,978)	(691,014)	(694,050)	(697,086)	(700,122)	(703,158)	(706,194)	(709,230)	(712,266)	(715,302)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$305,924	302,888	299,852	296,816	293,780	290,744	287,708	284,672	281,636	278,600	275,564	272,528	269,492	
6.	Average Net Investment		304,406	301,370	298,334	295,298	292,262	289,226	286,190	283,154	280,118	277,082	274,046	271,010	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$1,462	$1,447	$1,433	$1,418	$1,404	$1,389	$1,384	$1,370	$1,355	$1,340	$1,326	$1,311	$16,639
	b. Debt Component Grossed Up For Taxes (C)		456	451	446	442	437	433	409	405	400	396	392	387	5,054
8.	Investment Expenses														
	a. Depreciation (D)		$3,036	$3,036	$3,036	$3,036	$3,036	$3,036	$3,036	$3,036	$3,036	$3,036	$3,036	$3,036	$36,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,954	4,934	4,915	4,896	4,877	4,858	4,829	4,811	4,791	4,772	4,754	4,734	58,125
	a. Recoverable Costs Allocated to Energy		4,954	4,934	4,915	4,896	4,877	4,858	4,829	4,811	4,791	4,772	4,754	4,734	58,125
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		4,954	4,934	4,915	4,896	4,877	4,858	4,829	4,811	4,791	4,772	4,754	4,734	58,125
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,954	$4,934	$4,915	$4,896	$4,877	$4,858	$4,829	$4,811	$4,791	$4,772	$4,754	$4,734	$58,125

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% 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
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Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(51,907)	(52,199)	(52,491)	(52,783)	(53,075)	(53,367)	(53,659)	(53,951)	(54,243)	(54,535)	(54,827)	(55,119)	(55,411)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$68,830	68,538	68,246	67,954	67,662	67,370	67,078	66,786	66,494	66,202	65,910	65,618	65,326	
6.	Average Net Investment		68,684	68,392	68,100	67,808	67,516	67,224	66,932	66,640	66,348	66,056	65,764	65,472	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$330	$328	$327	$326	$324	$323	$324	$322	$321	$320	$318	$317	$3,880
	b. Debt Component Grossed Up For Taxes (C)		103	102	102	101	101	101	96	95	95	94	94	94	1,178
8.	Investment Expenses														
	a. Depreciation (D)		$292	$292	$292	$292	$292	$292	$292	$292	$292	$292	$292	$292	$3,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		725	722	721	719	717	716	712	709	708	706	704	703	8,562
	a. Recoverable Costs Allocated to Energy		725	722	721	719	717	716	712	709	708	706	704	703	8,562
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		725	722	721	719	717	716	712	709	708	706	704	703	8,562
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$725	$722	$721	$719	$717	$716	$712	$709	$708	$706	$704	$703	$8,562

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	$95,255,242	
3.	Less: Accumulated Depreciation	(55,074,209)	(55,336,128)	(55,598,047)	(55,859,966)	(56,121,885)	(56,383,804)	(56,645,723)	(56,907,642)	(57,169,561)	(57,431,480)	(57,693,399)	(57,955,318)	(58,217,237)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$40,181,033	39,919,114	39,657,195	39,395,276	39,133,357	38,871,438	38,609,519	38,347,600	38,085,681	37,823,762	37,561,843	37,299,924	37,038,005	
6.	Average Net Investment		40,050,073	39,788,154	39,526,235	39,264,316	39,002,397	38,740,478	38,478,559	38,216,640	37,954,721	37,692,802	37,430,883	37,168,964	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$192,334	$191,076	$189,818	$188,560	$187,303	$186,045	$186,127	$184,860	$183,593	$182,326	$181,059	$179,792	$2,232,893
	b. Debt Component Grossed Up For Taxes (C)		59,938	59,546	59,154	58,762	58,370	57,978	54,973	54,599	54,225	53,850	53,476	53,102	677,973
8.	Investment Expenses														
	a. Depreciation (D)		$261,919	$261,919	$261,919	$261,919	$261,919	$261,919	$261,919	$261,919	$261,919	$261,919	$261,919	$261,919	$3,143,028
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		514,191	512,541	510,891	509,241	507,592	505,942	503,019	501,378	499,737	498,095	496,454	494,813	6,053,894
	a. Recoverable Costs Allocated to Energy		514,191	512,541	510,891	509,241	507,592	505,942	503,019	501,378	499,737	498,095	496,454	494,813	6,053,894
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		514,191	512,541	510,891	509,241	507,592	505,942	503,019	501,378	499,737	498,095	496,454	494,813	6,053,894
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$514,191	$512,541	$510,891	$509,241	$507,592	$505,942	$503,019	$501,378	$499,737	$498,095	$496,454	$494,813	$6,053,894

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.46 ($94,929,061), 312.45 ($105,398) & 315.46 ($220,782)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 3.3%, 2.5% and 3.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$29,435	$7,632	$61,810	$126,316	$377,714	$71,808	$45,911	$100,000	$100,000	$100,000	$100,000	$100,000	$1,220,627
	b. Clearings to Plant		29,435	7,632	61,810	126,316	377,714	71,808	0	45,911	100,000	100,000	100,000	100,000	1,120,627
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,769,172	$21,776,804	$21,838,615	$21,964,930	$22,342,644	$22,414,453	$22,414,453	$22,460,364	$22,560,364	$22,660,364	$22,760,364	$22,860,364	
3.	Less: Accumulated Depreciation	(8,790,925)	(8,836,199)	(8,881,576)	(8,926,971)	(8,972,493)	(9,018,278)	(9,064,850)	(9,111,581)	(9,158,312)	(9,205,139)	(9,252,174)	(9,299,418)	(9,346,870)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	45,911	100,000	100,000	100,000	100,000	100,000	
5.	Net Investment (Lines 2 + 3 + 4)	$12,948,812	12,932,973	12,895,228	12,911,644	12,992,437	13,324,366	13,349,603	13,348,783	13,402,052	13,455,225	13,508,190	13,560,946	13,613,494	
6.	Average Net Investment		12,940,893	12,914,101	12,903,436	12,952,040	13,158,402	13,336,985	13,349,193	13,375,417	13,428,638	13,481,707	13,534,568	13,587,220	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$62,146	$62,018	$61,967	$62,200	$63,191	$64,049	$64,572	$64,699	$64,957	$65,213	$65,469	$65,724	$766,205
	b. Debt Component Grossed Up For Taxes (C)		19,367	19,327	19,311	19,384	19,693	19,960	19,072	19,109	19,185	19,261	19,336	19,412	232,417
8.	Investment Expenses														
	a. Depreciation (D)		$45,274	$45,377	$45,395	$45,522	$45,785	$46,572	$46,731	$46,731	$46,827	$47,035	$47,244	$47,452	$555,945
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		126,787	126,722	126,673	127,106	128,669	130,581	130,375	130,539	130,969	131,509	132,049	132,588	1,554,567
	a. Recoverable Costs Allocated to Energy		126,787	126,722	126,673	127,106	128,669	130,581	130,375	130,539	130,969	131,509	132,049	132,588	1,554,567
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		126,787	126,722	126,673	127,106	128,669	130,581	130,375	130,539	130,969	131,509	132,049	132,588	1,554,567
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$126,787	$126,722	$126,673	$127,106	$128,669	$130,581	$130,375	$130,539	$130,969	$131,509	$132,049	$132,588	$1,554,567

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($22,784,292),311.45 ($39,818) and 316.40 ($36,254)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.5%, 2.0% and 4.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Actual November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	1,871,979	1,861,795	1,851,611	1,841,427	1,831,243	1,821,059	1,810,875	1,800,691	1,790,507	1,780,323	1,770,139	1,759,955	1,749,771	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,062,831	5,052,647	5,042,463	5,032,279	5,022,095	5,011,911	5,001,727	4,991,543	4,981,359	4,971,175	4,960,991	4,950,807	4,940,623	
6.	Average Net Investment		5,057,739	5,047,555	5,037,371	5,027,187	5,017,003	5,006,819	4,996,635	4,986,451	4,976,267	4,966,083	4,955,899	4,945,715	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$24,289	$24,240	$24,191	$24,142	$24,093	$24,044	$24,170	$24,120	$24,071	$24,022	$23,973	$23,923	$289,278
	b. Debt Component Grossed Up For Taxes (C)		7,569	7,554	7,539	7,524	7,508	7,493	7,139	7,124	7,109	7,095	7,080	7,066	87,800
8.	Investment Expenses														
	a. Depreciation (D)		$10,184	$10,184	$10,184	$10,184	$10,184	$10,184	$10,184	$10,184	$10,184	$10,184	$10,184	$10,184	$122,208
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		42,042	41,978	41,914	41,850	41,785	41,721	41,493	41,428	41,364	41,301	41,237	41,173	499,286
	a. Recoverable Costs Allocated to Energy		42,042	41,978	41,914	41,850	41,785	41,721	41,493	41,428	41,364	41,301	41,237	41,173	499,286
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		42,042	41,978	41,914	41,850	41,785	41,721	41,493	41,428	41,364	41,301	41,237	41,173	499,286
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$42,042	$41,978	$41,914	$41,850	$41,785	$41,721	$41,493	$41,428	$41,364	$41,301	$41,237	$41,173	$499,286

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963).
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% 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 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		($24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($24)
	b. Clearings to Plant		(24)	0	0	0	0	0	0	0	0	0	0	0	(24)
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$19,757,774	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	$19,757,750	
3.	Less: Accumulated Depreciation	(5,083,858)	(5,144,730)	(5,205,602)	(5,266,474)	(5,327,346)	(5,388,218)	(5,449,090)	(5,509,962)	(5,570,834)	(5,631,706)	(5,692,578)	(5,753,450)	(5,814,322)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$14,673,916	14,613,020	14,552,148	14,491,276	14,430,404	14,369,532	14,308,660	14,247,788	14,186,916	14,126,044	14,065,172	14,004,300	13,943,428	
6.	Average Net Investment		14,643,468	14,582,584	14,521,712	14,460,840	14,399,968	14,339,096	14,278,224	14,217,352	14,156,480	14,095,608	14,034,736	13,973,864	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$70,323	$70,030	$69,738	$69,446	$69,153	$68,861	$69,066	$68,772	$68,477	$68,183	$67,888	$67,594	$827,531
	b. Debt Component Grossed Up For Taxes (C)		21,915	21,824	21,733	21,642	21,551	21,460	20,399	20,312	20,225	20,138	20,051	19,964	251,214
8.	Investment Expenses														
	a. Depreciation (D)		$60,872	$60,872	$60,872	$60,872	$60,872	$60,872	$60,872	$60,872	$60,872	$60,872	$60,872	$60,872	$730,464
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		153,110	152,726	152,343	151,960	151,576	151,193	150,337	149,956	149,574	149,193	148,811	148,430	1,809,209
	a. Recoverable Costs Allocated to Energy		153,110	152,726	152,343	151,960	151,576	151,193	150,337	149,956	149,574	149,193	148,811	148,430	1,809,209
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		153,110	152,726	152,343	151,960	151,576	151,193	150,337	149,956	149,574	149,193	148,811	148,430	1,809,209
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$153,110	$152,726	$152,343	$151,960	$151,576	$151,193	$150,337	$149,956	$149,574	$149,193	$148,811	$148,430	$1,809,209

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($5,831,465), 312.42 ($5,153,072), 312.43 ($7,875,560), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($528,554)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 4.0%, 3.7%, 3.5%, 3.5%, 3.2%, and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(736,410)	(740,834)	(745,258)	(749,682)	(754,106)	(758,530)	(762,954)	(767,378)	(771,802)	(776,226)	(780,650)	(785,074)	(789,498)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$825,063	820,639	816,215	811,791	807,367	802,943	798,519	794,095	789,671	785,247	780,823	776,399	771,975	
6.	Average Net Investment		822,851	818,427	814,003	809,579	805,155	800,731	796,307	791,883	787,459	783,035	778,611	774,187	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,952	$3,930	$3,909	$3,888	$3,867	$3,845	$3,852	$3,830	$3,809	$3,788	$3,766	$3,745	$46,181
	b. Debt Component Grossed Up For Taxes (C)		1,231	1,225	1,218	1,212	1,205	1,198	1,138	1,131	1,125	1,119	1,112	1,106	14,020
8.	Investment Expenses														
	a. Depreciation (D)		$4,424	$4,424	$4,424	$4,424	$4,424	$4,424	$4,424	$4,424	$4,424	$4,424	$4,424	$4,424	$53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,385	9,358	9,331	9,302	9,275	113,289
	a. Recoverable Costs Allocated to Energy		9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,385	9,358	9,331	9,302	9,275	113,289
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,385	9,358	9,331	9,302	9,275	113,289
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$9,607	$9,579	$9,551	$9,524	$9,496	$9,467	$9,414	$9,385	$9,358	$9,331	$9,302	$9,275	$113,289

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(909,434)	(915,831)	(922,228)	(928,625)	(935,022)	(941,419)	(947,816)	(954,213)	(960,610)	(967,007)	(973,404)	(979,801)	(986,198)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,649,296	1,642,899	1,636,502	1,630,105	1,623,708	1,617,311	1,610,914	1,604,517	1,598,120	1,591,723	1,585,326	1,578,929	1,572,532	
6.	Average Net Investment		1,646,098	1,639,701	1,633,304	1,626,907	1,620,510	1,614,113	1,607,716	1,601,319	1,594,922	1,588,525	1,582,128	1,575,731	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$7,905	$7,874	$7,844	$7,813	$7,782	$7,752	$7,777	$7,746	$7,715	$7,684	$7,653	$7,622	$93,167
	b. Debt Component Grossed Up For Taxes (C)		2,464	2,454	2,444	2,435	2,425	2,416	2,297	2,288	2,279	2,269	2,260	2,251	28,282
8.	Investment Expenses														
	a. Depreciation (D)		$6,397	$6,397	$6,397	$6,397	$6,397	$6,397	$6,397	$6,397	$6,397	$6,397	$6,397	$6,397	$76,764
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,350	16,310	16,270	198,213
	a. Recoverable Costs Allocated to Energy		16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,350	16,310	16,270	198,213
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,350	16,310	16,270	198,213
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,766	$16,725	$16,685	$16,645	$16,604	$16,565	$16,471	$16,431	$16,391	$16,350	$16,310	$16,270	$198,213

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% 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 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(665,629)	(671,126)	(676,623)	(682,120)	(687,617)	(693,114)	(698,611)	(704,108)	(709,605)	(715,102)	(720,599)	(726,096)	(731,593)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$983,492	977,995	972,498	967,001	961,504	956,007	950,510	945,013	939,516	934,019	928,522	923,025	917,528	
6.	Average Net Investment		980,744	975,247	969,750	964,253	958,756	953,259	947,762	942,265	936,768	931,271	925,774	920,277	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,710	$4,683	$4,657	$4,631	$4,604	$4,578	$4,584	$4,558	$4,531	$4,505	$4,478	$4,452	$54,971
	b. Debt Component Grossed Up For Taxes (C)		1,468	1,460	1,451	1,443	1,435	1,427	1,354	1,346	1,338	1,330	1,323	1,315	16,690
8.	Investment Expenses														
	a. Depreciation (D)		$5,497	$5,497	$5,497	$5,497	$5,497	$5,497	$5,497	$5,497	$5,497	$5,497	$5,497	$5,497	$65,964
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		11,675	11,640	11,605	11,571	11,536	11,502	11,435	11,401	11,366	11,332	11,298	11,264	137,625
	a. Recoverable Costs Allocated to Energy		11,675	11,640	11,605	11,571	11,536	11,502	11,435	11,401	11,366	11,332	11,298	11,264	137,625
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		11,675	11,640	11,605	11,571	11,536	11,502	11,435	11,401	11,366	11,332	11,298	11,264	137,625
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$11,675	$11,640	$11,605	$11,571	$11,536	$11,502	$11,435	$11,401	$11,366	$11,332	$11,298	$11,264	$137,625

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(594,320)	(599,197)	(604,074)	(608,951)	(613,828)	(618,705)	(623,582)	(628,459)	(633,336)	(638,213)	(643,090)	(647,967)	(652,844)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$987,567	982,690	977,813	972,936	968,059	963,182	958,305	953,428	948,551	943,674	938,797	933,920	929,043	
6.	Average Net Investment		985,129	980,252	975,375	970,498	965,621	960,744	955,867	950,990	946,113	941,236	936,359	931,482	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$4,731	$4,707	$4,684	$4,661	$4,637	$4,614	$4,624	$4,600	$4,577	$4,553	$4,529	$4,506	$55,423
	b. Debt Component Grossed Up For Taxes (C)		1,474	1,467	1,460	1,452	1,445	1,438	1,366	1,359	1,352	1,345	1,338	1,331	16,827
8.	Investment Expenses														
	a. Depreciation (D)		$4,877	$4,877	$4,877	$4,877	$4,877	$4,877	$4,877	$4,877	$4,877	$4,877	$4,877	$4,877	$58,524
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774
	a. Recoverable Costs Allocated to Energy		11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$11,082	$11,051	$11,021	$10,990	$10,959	$10,929	$10,867	$10,836	$10,806	$10,775	$10,744	$10,714	$130,774

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(832,202)	(840,155)	(848,108)	(856,061)	(864,014)	(871,967)	(879,920)	(887,873)	(895,826)	(903,779)	(911,732)	(919,685)	(927,638)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,874,305	1,866,352	1,858,399	1,850,446	1,842,493	1,834,540	1,826,587	1,818,634	1,810,681	1,802,728	1,794,775	1,786,822	1,778,869	
6.	Average Net Investment		1,870,329	1,862,376	1,854,423	1,846,470	1,838,517	1,830,564	1,822,611	1,814,658	1,806,705	1,798,752	1,790,799	1,782,846	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$8,982	$8,944	$8,906	$8,867	$8,829	$8,791	$8,816	$8,778	$8,739	$8,701	$8,662	$8,624	$105,639
	b. Debt Component Grossed Up For Taxes (C)		2,799	2,787	2,775	2,763	2,751	2,740	2,604	2,593	2,581	2,570	2,558	2,547	32,068
8.	Investment Expenses														
	a. Depreciation (D)		$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		19,734	19,684	19,634	19,583	19,533	19,484	19,373	19,324	19,273	19,224	19,173	19,124	233,143
	a. Recoverable Costs Allocated to Energy		19,734	19,684	19,634	19,583	19,533	19,484	19,373	19,324	19,273	19,224	19,173	19,124	233,143
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		19,734	19,684	19,634	19,583	19,533	19,484	19,373	19,324	19,273	19,224	19,173	19,124	233,143
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$19,734	$19,684	$19,634	$19,583	$19,533	$19,484	$19,373	$19,324	$19,273	$19,224	$19,173	$19,124	$233,143

Notes:

(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 3.5% and 3.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	$85,719,102	
3.	Less: Accumulated Depreciation	(28,849,638)	(29,158,804)	(29,467,970)	(29,777,136)	(30,086,302)	(30,395,468)	(30,704,634)	(31,013,800)	(31,322,966)	(31,632,132)	(31,941,298)	(32,250,464)	(32,559,630)	
4.	CWIP - Non-Interest Bearing	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	1,362,824	
5.	Net Investment (Lines 2 + 3 + 4)	$58,232,288	57,923,122	57,613,956	57,304,790	56,995,624	56,686,458	56,377,292	56,068,126	55,758,960	55,449,794	55,140,628	54,831,462	54,522,296	
6.	Average Net Investment		58,077,705	57,768,539	57,459,373	57,150,207	56,841,041	56,531,875	56,222,709	55,913,543	55,604,377	55,295,211	54,986,045	54,676,879	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$278,908	$277,424	$275,939	$274,454	$272,970	$271,485	$271,959	$270,463	$268,968	$267,472	$265,977	$264,481	$3,260,500
	b. Debt Component Grossed Up For Taxes (C)		86,918	86,455	85,993	85,530	85,067	84,605	80,324	79,882	79,440	78,998	78,557	78,115	989,884
8.	Investment Expenses														
	a. Depreciation (D)		$309,166	$309,166	$309,166	$309,166	$309,166	$309,166	$309,166	$309,166	$309,166	$309,166	$309,166	$309,166	$3,709,992
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		674,992	673,045	671,098	669,150	667,203	665,256	661,449	659,511	657,574	655,636	653,700	651,762	7,960,376
	a. Recoverable Costs Allocated to Energy		674,992	673,045	671,098	669,150	667,203	665,256	661,449	659,511	657,574	655,636	653,700	651,762	7,960,376
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		674,992	673,045	671,098	669,150	667,203	665,256	661,449	659,511	657,574	655,636	653,700	651,762	7,960,376
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$674,992	$673,045	$671,098	$669,150	$667,203	$665,256	$661,449	$659,511	$657,574	$655,636	$653,700	$651,762	$7,960,376

Notes:

(A) Applicable depreciable base for Big Bend; account 311.51 ($22,278,982), 312.51 ($48,529,672), 315.51 ($14,063,245), and 316.51 ($847,203).
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 4.1%, 4.3%, 4.8% and 4.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	$95,175,309	
3.	Less: Accumulated Depreciation	(30,814,532)	(31,122,366)	(31,430,200)	(31,738,034)	(32,045,868)	(32,353,702)	(32,661,536)	(32,969,370)	(33,277,204)	(33,585,038)	(33,892,872)	(34,200,706)	(34,508,540)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$64,360,777	64,052,943	63,745,109	63,437,275	63,129,441	62,821,607	62,513,773	62,205,939	61,898,105	61,590,271	61,282,437	60,974,603	60,666,769	
6.	Average Net Investment		64,206,860	63,899,026	63,591,192	63,283,358	62,975,524	62,667,690	62,359,856	62,052,022	61,744,188	61,436,354	61,128,520	60,820,686	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$308,343	$306,864	$305,386	$303,908	$302,429	$300,951	$301,645	$300,156	$298,667	$297,178	$295,689	$294,200	$3,615,416
	b. Debt Component Grossed Up For Taxes (C)		96,091	95,630	95,170	94,709	94,248	93,787	89,091	88,652	88,212	87,772	87,332	86,892	1,097,586
8.	Investment Expenses														
	a. Depreciation (D)		$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$307,834	$3,694,008
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		712,268	710,328	708,390	706,451	704,511	702,572	698,570	696,642	694,713	692,784	690,855	688,926	8,407,010
	a. Recoverable Costs Allocated to Energy		712,268	710,328	708,390	706,451	704,511	702,572	698,570	696,642	694,713	692,784	690,855	688,926	8,407,010
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		712,268	710,328	708,390	706,451	704,511	702,572	698,570	696,642	694,713	692,784	690,855	688,926	8,407,010
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$712,268	$710,328	$708,390	$706,451	$704,511	$702,572	$698,570	$696,642	$694,713	$692,784	$690,855	$688,926	$8,407,010

Notes:

(A) Applicable depreciable base for Big Bend; account 311.52 ($25,208,869), 312.52 ($53,093,397), 315.52 ($15,914,427), and 316.52 ($958,616).
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 3.5%, 4.0%, 4.1% and 3.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	$81,764,602	
3.	Less: Accumulated Depreciation	(27,938,697)	(28,190,771)	(28,442,845)	(28,694,919)	(28,946,993)	(29,199,067)	(29,451,141)	(29,703,215)	(29,955,289)	(30,207,363)	(30,459,437)	(30,711,511)	(30,963,585)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$53,825,905	53,573,831	53,321,757	53,069,683	52,817,609	52,565,535	52,313,461	52,061,387	51,809,313	51,557,239	51,305,165	51,053,091	50,801,017	
6.	Average Net Investment		53,699,868	53,447,794	53,195,720	52,943,646	52,691,572	52,439,498	52,187,424	51,935,350	51,683,276	51,431,202	51,179,128	50,927,054	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$257,885	$256,674	$255,464	$254,253	$253,042	$251,832	$252,439	$251,220	$250,001	$248,781	$247,562	$246,343	$3,025,496
	b. Debt Component Grossed Up For Taxes (C)		80,366	79,989	79,612	79,235	78,857	78,480	74,558	74,198	73,838	73,478	73,118	72,758	918,487
8.	Investment Expenses														
	a. Depreciation (D)		$252,074	$252,074	$252,074	$252,074	$252,074	$252,074	$252,074	$252,074	$252,074	$252,074	$252,074	$252,074	$3,024,888
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		590,325	588,737	587,150	585,562	583,973	582,386	579,071	577,492	575,913	574,333	572,754	571,175	6,968,871
	a. Recoverable Costs Allocated to Energy		590,325	588,737	587,150	585,562	583,973	582,386	579,071	577,492	575,913	574,333	572,754	571,175	6,968,871
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		590,325	588,737	587,150	585,562	583,973	582,386	579,071	577,492	575,913	574,333	572,754	571,175	6,968,871
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$590,325	$588,737	$587,150	$585,562	$583,973	$582,386	$579,071	$577,492	$575,913	$574,333	$572,754	$571,175	$6,968,871

Notes:
(A) Applicable depreciable base for Big Bend; account 311.53 ($21,689,422), 312.53 ($45,559,543), 315.53 ($13,690,954), and 316.53 ($824,684).
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% 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 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	($34)	$431	$2,699	$5,941	$7,263	$450,000	$0	$450,000	$0	$0	$0	$916,300
	b. Clearings to Plant		0	(34)	0	0	0	0	0	0	0	0	0	0	(34)
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$65,312,615	$65,312,615	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	
3.	Less: Accumulated Depreciation	(22,513,773)	(22,701,483)	(22,889,193)	(23,076,903)	(23,264,613)	(23,452,323)	(23,640,033)	(23,827,743)	(24,015,453)	(24,203,163)	(24,390,873)	(24,578,583)	(24,766,293)	
4.	CWIP - Non-Interest Bearing	0	0	0	431	3,131	9,071	16,335	466,335	466,335	916,335	916,335	916,335	916,335	
5.	Net Investment (Lines 2 + 3 + 4)	$42,798,842	42,611,132	42,423,388	42,236,109	42,051,098	41,869,329	41,688,882	41,951,172	41,763,462	42,025,752	41,838,042	41,650,332	41,462,622	
6.	Average Net Investment		42,704,987	42,517,260	42,329,748	42,143,603	41,960,213	41,779,105	41,820,027	41,857,317	41,894,607	41,931,897	41,744,187	41,556,477	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$205,084	$204,182	$203,282	$202,388	$201,507	$200,637	$202,290	$202,471	$202,651	$202,832	$201,924	$201,016	$2,430,264
	b. Debt Component Grossed Up For Taxes (C)		63,912	63,631	63,350	63,071	62,797	62,526	59,747	59,800	59,853	59,907	59,639	59,370	737,603
8.	Investment Expenses														
	a. Depreciation (D)		$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$2,252,520
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		456,706	455,523	454,342	453,169	452,014	450,873	449,747	449,981	450,214	450,449	449,273	448,096	5,420,387
	a. Recoverable Costs Allocated to Energy		456,706	455,523	454,342	453,169	452,014	450,873	449,747	449,981	450,214	450,449	449,273	448,096	5,420,387
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		456,706	455,523	454,342	453,169	452,014	450,873	449,747	449,981	450,214	450,449	449,273	448,096	5,420,387
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$456,706	$455,523	$454,342	$453,169	$452,014	$450,873	$449,747	$449,981	$450,214	$450,449	$449,273	$448,096	$5,420,387

Notes:
(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($36,567,266), 315.54 ($10,642,027), 316.54 ($687,934), and 315.40 ($558,103)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rates are 2.4%, 3.8%, 3.9%, 3.3%, and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	
3.	Less: Accumulated Depreciation	(4,600,662)	(4,651,971)	(4,703,280)	(4,754,589)	(4,805,898)	(4,857,207)	(4,908,516)	(4,959,825)	(5,011,134)	(5,062,443)	(5,113,752)	(5,165,061)	(5,216,370)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$19,736,045	19,684,736	19,633,427	19,582,118	19,530,809	19,479,500	19,428,191	19,376,882	19,325,573	19,274,264	19,222,955	19,171,646	19,120,337	
6.	Average Net Investment		19,710,391	19,659,082	19,607,773	19,556,464	19,505,155	19,453,846	19,402,537	19,351,228	19,299,919	19,248,610	19,197,301	19,145,992	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$94,656	$94,409	$94,163	$93,917	$93,670	$93,424	$93,853	$93,605	$93,357	$93,109	$92,861	$92,612	$1,123,636
	b. Debt Component Grossed Up For Taxes (C)		29,498	29,421	29,345	29,268	29,191	29,114	27,720	27,646	27,573	27,500	27,427	27,353	341,056
8.	Investment Expenses														
	a. Depreciation (D)		$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$615,708
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		175,463	175,139	174,817	174,494	174,170	173,847	172,882	172,560	172,239	171,918	171,597	171,274	2,080,400
	a. Recoverable Costs Allocated to Energy		175,463	175,139	174,817	174,494	174,170	173,847	172,882	172,560	172,239	171,918	171,597	171,274	2,080,400
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		175,463	175,139	174,817	174,494	174,170	173,847	172,882	172,560	172,239	171,918	171,597	171,274	2,080,400
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$175,463	$175,139	$174,817	$174,494	$174,170	$173,847	$172,882	$172,560	$172,239	$171,918	$171,597	$171,274	$2,080,400

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45 ($22,880,499) and 312.44 ($1,456,209).
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% 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
Calculation of the Current Period Actual / Estimated Amount
January 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Mercury Air Toxics Standards (MATS)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$21,483	$0	$0	$0	$20,095	$0	$350,000	$0	$0	$0	$391,578
	b. Clearings to Plant		0	0	0	21,483	0	0	0	0	0	0	0	20,095	41,578
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,586,395	$8,586,395	$8,586,395	$8,586,395	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,607,879	$8,627,974	
3.	Less: Accumulated Depreciation	(1,155,720)	(1,177,599)	(1,199,478)	(1,221,357)	(1,243,236)	(1,265,371)	(1,287,506)	(1,309,641)	(1,331,776)	(1,353,911)	(1,376,046)	(1,398,181)	(1,420,316)	
4.	CWIP - Non-Interest Bearing	0	0	0	21,483	0	0	0	20,095	20,095	370,095	370,095	370,095	350,000	
5.	Net Investment (Lines 2 + 3 + 4)	$7,430,675	7,408,796	7,386,917	7,386,522	7,364,643	7,342,508	7,320,373	7,318,333	7,296,198	7,624,063	7,601,928	7,579,793	7,557,658	
6.	Average Net Investment		7,419,736	7,397,857	7,386,720	7,375,582	7,353,575	7,331,440	7,319,353	7,307,265	7,460,130	7,612,995	7,590,860	7,568,725	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$35,632	$35,527	$35,473	$35,420	$35,314	$35,208	$35,405	$35,346	$36,086	$36,825	$36,718	$36,611	$429,565
	b. Debt Component Grossed Up For Taxes (C)		11,104	11,072	11,055	11,038	11,005	10,972	10,457	10,440	10,658	10,876	10,845	10,813	130,335
8.	Investment Expenses														
	a. Depreciation (D)		$21,879	$21,879	$21,879	$21,879	$22,135	$22,135	$22,135	$22,135	$22,135	$22,135	$22,135	$22,135	$264,596
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		68,615	68,478	68,407	68,337	68,454	68,315	67,997	67,921	68,879	69,836	69,698	69,559	824,496
	a. Recoverable Costs Allocated to Energy		68,615	68,478	68,407	68,337	68,454	68,315	67,997	67,921	68,879	69,836	69,698	69,559	824,496
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		68,615	68,478	68,407	68,337	68,454	68,315	67,997	67,921	68,879	69,836	69,698	69,559	824,496
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$68,615	$68,478	$68,407	$68,337	$68,454	$68,315	$67,997	$67,921	$68,879	$69,836	$69,698	$69,559	$824,496

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.44 ($3,427,481), 341.80($26,150), 315.40 ($1,226,949), 315.41 ($138,853), 315.42 ($138,853), 312.45 ($2,053,017), 312.46 ($1,242,315), 315.44 ($16,035), 315.45 ($40,217) and 315.46 ($50,784), 311.40 ($13,216), 345.81 ($22,327), 312.54 ($210,295) and 395.00 ($21,483)

(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)

(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)

(D) Applicable depreciation rate is 3.0%, 2.2%, 3.7%, 3.5%, 3.3%, 2.5%, 3.3%, 3.2%, 3.1%, 3.5%, 2.9%, 3.3%, 3.8% and 14.3%

(E) Line 9a x Line 10

(F) Line 9b x Line 11

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

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	0	0	97	0	0	0	0	0	0	97
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(34,513)	(34,472)	(34,472)	(34,472)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	
3.	Total Working Capital Balance	($34,513)	(34,472)	(34,472)	(34,472)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	
4.	Average Net Working Capital Balance		(34,493)	(34,472)	(34,472)	(34,456)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	(34,440)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($166)	($166)	($166)	($165)	($165)	($165)	($167)	($167)	($167)	($167)	($167)	($167)	($1,995)
	b. Debt Component Grossed Up For Taxes (B)		(52)	(52)	(52)	(52)	(52)	(52)	(49)	(49)	(49)	(49)	(49)	(49)	(606)
6.	Total Return Component		(218)	(218)	(218)	(217)	(217)	(217)	(216)	(216)	(216)	(216)	(216)	(216)	(2,601)
7.	Expenses:														
	a. Gains		0	0	0	0	0	(97)	0	0	0	0	0	0	(97)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(34)	5	8	(16)	22	14	(50)	12	12	(33)	12	12	(36)
8.	Net Expenses (D)		(34)	5	8	(16)	22	(83)	(50)	12	12	(33)	12	12	(133)
9.	Total System Recoverable Expenses (Lines 6 + 8)		(252)	(213)	(210)	(233)	(195)	(300)	(266)	(204)	(204)	(249)	(204)	(204)	(2,734)
	a. Recoverable Costs Allocated to Energy		(252)	(213)	(210)	(233)	(195)	(300)	(266)	(204)	(204)	(249)	(204)	(204)	(2,734)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		(252)	(213)	(210)	(233)	(195)	(300)	(266)	(204)	(204)	(249)	(204)	(204)	(2,734)
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		($252)	($213)	($210)	($233)	($195)	($300)	($266)	($204)	($204)	($249)	($204)	($204)	($2,734)

Notes:
(A) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(B) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% 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 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Gypsum Storage Facility
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	$21,467,359	
3.	Less: Accumulated Depreciation	(1,909,779)	(1,961,658)	(2,013,537)	(2,065,416)	(2,117,295)	(2,169,174)	(2,221,053)	(2,272,932)	(2,324,811)	(2,376,690)	(2,428,569)	(2,480,448)	(2,532,327)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$19,557,580	19,505,701	19,453,822	19,401,943	19,350,064	19,298,185	19,246,306	19,194,427	19,142,548	19,090,669	19,038,790	18,986,911	18,935,032	
6.	Average Net Investment		19,531,641	19,479,762	19,427,883	19,376,004	19,324,125	19,272,246	19,220,367	19,168,488	19,116,609	19,064,730	19,012,851	18,960,972	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$93,797	$93,548	$93,299	$93,050	$92,801	$92,552	$92,972	$92,721	$92,470	$92,219	$91,968	$91,717	$1,113,114
	b. Debt Component Grossed Up For Taxes (C)		29,231	29,153	29,075	28,998	28,920	28,843	27,459	27,385	27,311	27,237	27,163	27,089	337,864
8.	Investment Expenses														
	a. Depreciation (D)		$51,879	$51,879	$51,879	$51,879	$51,879	$51,879	$51,879	$51,879	$51,879	$51,879	$51,879	$51,879	$622,548
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		174,907	174,580	174,253	173,927	173,600	173,274	172,310	171,985	171,660	171,335	171,010	170,685	2,073,526
	a. Recoverable Costs Allocated to Energy		174,907	174,580	174,253	173,927	173,600	173,274	172,310	171,985	171,660	171,335	171,010	170,685	2,073,526
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		174,907	174,580	174,253	173,927	173,600	173,274	172,310	171,985	171,660	171,335	171,010	170,685	2,073,526
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$174,907	$174,580	$174,253	$173,927	$173,600	$173,274	$172,310	$171,985	$171,660	$171,335	$171,010	$170,685	$2,073,526

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Coal Combustion Residual (CCR Rule) -Phase I
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$5,637	$51,314	$6,003	$11,226	$6,964	$13,389	$507,799	$140,200	$505,323	$121,700	$49,700	$190,184	$1,609,440
	b. Clearings to Plant		0	0	0	0	0	0	0	842,772	505,323	111,700	29,700	220,184	1,709,679
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$668,735	$668,735	$668,735	$668,735	$668,735	$668,735	$668,735	$668,735	$1,511,507	$2,016,830	$2,128,530	$2,158,230	$2,378,414	
3.	Less: Accumulated Depreciation	(8,097)	(9,769)	(11,441)	(13,113)	(14,785)	(16,457)	(18,129)	(19,801)	(21,473)	(25,252)	(30,294)	(35,615)	(41,011)	
4.	CWIP - Non-Interest Bearing	100,239	105,876	157,191	163,194	174,420	181,384	194,773	702,572	0	0	10,000	30,000	0	
5.	Net Investment (Lines 2 + 3 + 4)	$760,877	764,842	814,485	818,816	828,370	833,662	845,379	1,351,506	1,490,034	1,991,578	2,108,236	2,152,615	2,337,403	
6.	Average Net Investment		762,860	789,663	816,650	823,593	831,016	839,520	1,098,442	1,420,770	1,740,806	2,049,907	2,130,425	2,245,009	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$3,664	$3,792	$3,922	$3,955	$3,991	$4,032	$5,313	$6,873	$8,421	$9,916	$10,305	$10,859	$75,043
	b. Debt Component Grossed Up For Taxes (C)		1,142	1,182	1,222	1,233	1,244	1,256	1,569	2,030	2,487	2,929	3,044	3,207	22,545
8.	Investment Expenses														
	a. Depreciation (D)		$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$3,779	$5,042	$5,321	$5,396	$32,914
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,478	6,646	6,816	6,860	6,907	6,960	8,554	10,575	14,687	17,887	18,670	19,462	130,502
	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		6,478	6,646	6,816	6,860	6,907	6,960	8,554	10,575	14,687	17,887	18,670	19,462	130,502
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)		6,478	6,646	6,816	6,860	6,907	6,960	8,554	10,575	14,687	17,887	18,670	19,462	130,502
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,478	$6,646	$6,816	$6,860	$6,907	$6,960	$8,554	$10,575	$14,687	$17,887	$18,670	$19,462	$130,502

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% 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 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals (CCR Rule - Phase II)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$64	$788	$436	$934	$2,259	$18,519	$18,519	$18,519	$18,519	$18,519	$18,519	$115,595
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	64	851	1,287	2,221	4,481	23,000	41,519	60,038	78,557	97,076	115,595	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	64	851	1,287	2,221	4,481	23,000	41,519	60,038	78,557	97,076	115,595	
6.	Average Net Investment		0	32	457	1,069	1,754	3,351	13,740	32,259	50,778	69,297	87,816	106,335	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$2	$5	$8	$16	$66	$156	$246	$335	$425	$514	$1,773
	b. Debt Component Grossed Up For Taxes (C)		0	0	1	2	3	5	20	46	73	99	125	152	526
8.	Investment Expenses														
	a. Depreciation (D)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	3	7	11	21	86	202	319	434	550	666	2,299
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	3	7	11	21	86	202	319	434	550	666	2,299
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	3	7	11	21	86	202	319	434	550	666	2,299
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$3	$7	$11	$21	$86	$202	$319	$434	$550	$666	$2,299

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% 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 2018 to December 2018

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

Line	Description	Beginning of Period Amoun	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,000	$50,000	$50,000	$150,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	50,000	100,000	150,000	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	50,000	100,000	150,000	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	25,000	75,000	125,000	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$121	$363	$605	$1,089
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	0	0	0	36	107	179	322
8.	Investment Expenses														
	a. Depreciation (D)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	157	470	784	1,411
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	157	470	784	1,411
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	157	470	784	1,411
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$157	$470	$784	$1,411

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.5%
(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 2018 to December 2018

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Section 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amoun	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$75,000	$400,000	$500,000	$500,000	$500,000	$500,000	$2,475,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	75,000	475,000	975,000	1,475,000	1,975,000	2,475,000	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	75,000	475,000	975,000	1,475,000	1,975,000	2,475,000	
6.	Average Net Investment		0	0	0	0	0	0	37,500	275,000	725,000	1,225,000	1,725,000	2,225,000	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$0	$0	$0	$0	$0	$0	$181	$1,330	$3,507	$5,926	$8,344	$10,763	$30,051
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	0	0	0	54	393	1,036	1,750	2,464	3,179	8,876
8.	Investment Expenses														
	a. Depreciation (D)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	235	1,723	4,543	7,676	10,808	13,942	38,927
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	235	1,723	4,543	7,676	10,808	13,942	38,927
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	235	1,723	4,543	7,676	10,808	13,942	38,927
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$235	$1,723	$4,543	$7,676	$10,808	$13,942	$38,927

Notes:
(A) Applicable depreciable base for Big Bend; accounts 316.46 ($0) and 346.30 ($0)
(B) Line 6 x 5.7628% x 1/12 (Jan-Jun) and Line 6 x 5.8046% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7959% x 1/12 (Jan-Jun) and Line 6 x 1.7144% x 1/12 (Jul-Dec)
(D) Applicable depreciation rate is 2.9 and 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
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REVISED: 7/27/2018

Tampa Electric Company Form 42 - 9E
Environmental Cost Recovery Clause Page 1 of 2
Calculation of the Current Period Actual / Estimated Amount
January 2018 to June 2018

Calculation of Revenue Requirement Rate of Return
(In Dollars)

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

ITC split between Debt and Equity:

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

Deferred ITC - Weighted Cost:

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

Total Equity Cost Rate:

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

Total Debt Cost Rate:

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

Notes:

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

Tampa Electric Company Form 42 - 9E
Environmental Cost Recovery Clause Page 2 of 2
Calculation of the Current Period Actual / Estimated Amount
July 2018 to December 2018

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 %	(5)
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 = 0.0289% * 46.00%	0.0133%
Equity = 0.0289% * 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	1.34295
Total Equity Component	5.8046%

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%
	7.5190%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012 and 2017 Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012 and 2017 Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)
Column (5) - Per 2017 Settlement Agreement, through 2021, actual equity ratio is capped at 54%.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 28
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-3

INDEX

TAMPA ELECTRIC COMPANY

ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL/ESTIMATED TRUE-UP AMOUNT

FOR THE PERIOD

JANUARY 2018 THROUGH DECEMBER 2018

NOT INCLUDING THE COMPANY'S TWO

NEW PROPOSED ECRC PROJECTS

FORMS 42-1E THROUGH 42-7E

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Tampa Electric Company Form 42 - 1E

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

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	$13,300,562
2.	Interest Provision (Form 42-2E, Line 6)	212,412
3.	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4.	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2019 to December 2019 (Lines 1 + 2 + 3)	$13,512,974

DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. PAR-3, DOCUMENT NO. 1, PAGE 1 OF 1
REVISED: 7/27/2018

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

Form 42 - 2E

Current Period True-Up Amount
(in Dollars)

Line	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1. ECRC Revenues (net of Revenue Taxes)	$5,299,826	$4,794,184	$4,754,839	$4,804,461	$5,074,853	$5,873,006	$6,540,375	$6,493,000	$6,689,809	$5,928,024	$4,939,446	$4,863,661	$66,055,485
2. True-Up Provision	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,445	508,449	6,101,344
3. ECRC Revenues Applicable to Period (Lines 1 + 2) [1]	5,808,271	5,302,629	5,263,284	5,312,906	5,583,298	6,381,451	7,048,820	7,001,445	7,198,254	6,436,469	5,447,891	5,372,110	72,156,829
4. Jurisdictional ECRC Costs													
a. O & M Activities (Form 42-5E, Line 9)	1,874,870	2,166,060	1,373,137	959,540	1,185,543	743,043	405,177	403,175	395,441	910,226	1,021,725	1,269,328	12,707,265
b. Capital Investment Projects (Form 42-7E, Line 9)	3,891,399	3,881,399	3,871,500	3,861,963	3,853,761	3,845,686	3,837,324	3,830,992	3,828,049	3,824,306	3,815,639	3,806,983	46,149,001
c. Total Jurisdictional ECRC Costs	5,766,269	6,047,459	5,244,637	4,821,503	5,039,304	4,588,729	4,242,501	4,234,167	4,223,490	4,734,532	4,837,364	5,076,311	58,856,266
5. Over/Under Recovery (Line 3 - Line 4c) [1]	42,002.00	(744,830)	18,647	491,403	543,994.00	1,792,722.00	2,806,319.00	2,767,278.00	2,974,764.00	1,701,937.00	610,527.00	295,799	13,300,562
6. Interest Provision (Form 42-3E, Line 10)	9,356	8,341	8,197	8,382	8,410	9,750	14,605	20,783	25,645	31,017	33,987	33,939	212,412
7. Beginning Balance True-Up & Interest Provision [1]	6,101,344	5,644,257	4,399,323	3,917,722	3,909,062	3,953,021	5,247,048	7,559,527	9,839,143	12,331,107	13,555,616	13,691,685	6,101,344
a. Deferred True-Up from January to December 2018 (Order No. PSC-2018-0014-FOF-EI)	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666	1,498,666
8. True-Up Collected/(Refunded) (see Line 2)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,445)	(508,449)	(6,101,344)
9. End of Period Total True-Up (Lines 5+6+7+7a+8) [1]	7,142,923	5,897,989	5,416,388	5,407,728	5,451,687	6,745,714	9,058,193	11,337,809	13,829,773	15,054,282	15,190,351	15,011,640	15,011,640
10. Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11. End of Period Total True-Up (Lines 9 + 10) [1]	$7,142,923	$5,897,989	$5,416,388	$5,407,728	$5,451,687	$6,745,714	$9,058,193	$11,337,809	$13,829,773	$15,054,282	$15,190,351	$15,011,640	$15,011,640

DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. PAR-3, DOCUMENT NO. 2, PAGE 1 OF 1
REVISED: 7/27/2018

Form 42 - 3E

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

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	$7,600,010	$7,142,923	$5,897,989	$5,416,388	$5,407,728	$5,451,687	$6,745,714	$9,058,193	$11,337,809	$13,829,773	$15,054,282	$15,190,351	
2.	Ending True-Up Amount Before Interest	7,133,567	5,889,648	5,408,191	5,399,346	5,443,277	6,735,964	9,043,588	11,317,026	13,804,128	15,023,265	15,156,364	14,977,701	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2) [1]	14,733,577	13,032,571	11,306,180	10,815,734	10,851,005	12,187,651	15,789,302	20,375,219	25,141,937	28,853,038	30,210,646	30,168,052	
4.	Average True-Up Amount (Line 3 x 1/2) [1]	7,366,789	6,516,286	5,653,090	5,407,867	5,425,503	6,093,826	7,894,651	10,187,610	12,570,969	14,426,519	15,105,323	15,084,026	
5.	Interest Rate (First Day of Reporting Business Month)	1.58%	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	2.45%	2.45%	2.45%	2.70%	2.70%	
6.	Interest Rate (First Day of Subsequent Business Month)	1.46%	1.62%	1.86%	1.85%	1.86%	1.98%	2.45%	2.45%	2.45%	2.70%	2.70%	2.70%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6) [1]	3.04%	3.08%	3.48%	3.71%	3.71%	3.84%	4.43%	4.90%	4.90%	5.15%	5.40%	5.40%	
8.	Average Interest Rate (Line 7 x 1/2) [1]	1.520%	1.540%	1.740%	1.855%	1.855%	1.920%	2.215%	2.450%	2.450%	2.575%	2.700%	2.700%	
9.	Monthly Average Interest Rate (Line 8 x 1/12) [1]	0.127%	0.128%	0.145%	0.155%	0.155%	0.160%	0.185%	0.204%	0.204%	0.215%	0.225%	0.225%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$9,356	$8,341	$8,197	$8,382	$8,410	$9,750	$14,605	$20,783	$25,645	$31,017	$33,987	$33,939	$212,412

Tampa Electric Company Form 42 - 4E

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

Variance Report of O & M Activities
(In Dollars)

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

Notes:

Column (1) is the End of Period Totals on Form 42-5E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2018-0014-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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

Form 42 - 5E

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 FGD Integration	452,214	273,733	291,066	358,824	331,130	187,714	0	0	0	0	0	0	1,894,681		$1,894,681
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	(34)	5	8	(16)	22	(83)	0	0	0	0	0	0	(98)		(98)
	d. Big Bend Units 1 & 2 FGD	17,413	66,376	55,024	54,100	100,066	19,825	43,000	43,000	43,000	43,000	43,000	43,000	570,804		570,804
	e. Big Bend PM Minimization and Monitoring	52,762	44,712	67,899	54,273	45,912	27,938	15,000	15,000	8,065	25,000	25,000	25,000	406,562		406,562
	f. Big Bend NO_x Emissions Reduction	37	34,122	266	2,757	78	29,434	2,000	2,000	2,000	2,000	2,000	2,000	78,693		78,693
	g. NPDES Annual Surveillance Fees	34,500	0	0	0	0	1,383	0	0	0	0	0	0	35,883	$35,883	
	h. Gannon Thermal Discharge Study	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	i. Polk NO_x Emissions Reduction	688	853	440	0	0	35	950	950	400	0	250	750	5,317		5,317
	j. Bayside SCR and Ammonia	16,454	3,210	8,560	12,325	3,210	11,843	12,500	10,000	9,000	8,000	8,000	8,000	111,102		111,102
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	0	0	39	0	0	0	0	0	0	0	0	0	39		39
	m. Big Bend Unit 2 Pre-SCR	635	0	0	815	0	0	0	0	0	0	0	0	1,450		1,450
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0	3,714	94	0	0	0	0	0	0	3,808		3,808
	o. Clean Water Act Section 316(b) Phase II Study	4,499	14,303	174	21,348	75	9	0	1,250	1,250	1,250	12,500	17,500	74,158	74,158	
	p. Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	q. Big Bend 1 SCR	6,777	18,340	3,087	32,717	33,063	14,694	40,801	41,277	39,690	50,168	24,607	45,881	351,102		351,102
	r. Big Bend 2 SCR	4,267	6,863	6,549	54,763	9,514	7,682	45,405	45,722	47,627	60,328	24,607	47,786	361,113		361,113
	s. Big Bend 3 SCR	125,936	154,048	270,635	166,420	280,869	192,408	60,405	60,722	62,627	33,098	83,425	62,791	1,553,384		1,553,384
	t. Big Bend 4 SCR	58,197	89,093	46,317	54,593	33,834	55,218	51,866	50,754	48,532	54,882	65,836	42,023	651,145		651,145
	u. Mercury Air Toxics Standards	0	0	7,823	55	0	0	3,250	2,500	3,250	2,500	2,500	2,500	24,378		24,378
	v. Greenhouse Gas Reduction Program	2,825	0	0	0	93,149	0	0	0	0	0	0	0	95,974		95,974
	w. Big Bend Gypsum Storage Facility (East 40)	163,867	110,837	59,289	124,795	239,532	159,952	130,000	130,000	130,000	130,000	130,000	130,000	1,638,273		1,638,273
	x. CCR Rule - Phase I	(3,500)	14,103	14,033	1,844	9,875	1,895	0	0	0	0	0	0	38,250		38,250
	y. Big Bend ELG Rule Study	0	11,472	0	9,832	0	32,703	0	0	0	0	0	0	54,007		54,007
	z. CCR Rule - Phase II	937,333	1,323,990	541,927	10,095	1,500	297	0	0	0	500,000	600,000	842,097	4,757,238		4,757,238
	aa. BB Unit 1 Section 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	ab. Big Bend ELG Rule Compliance	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	1,874,870	2,166,060	1,373,137	959,540	1,185,543	743,043	405,177	403,175	395,441	910,226	1,021,725	1,269,328	12,707,265	$110,042	$12,597,223
3.	Recoverable Costs Allocated to Energy	1,835,871	2,151,757	1,372,963	938,192	1,185,468	741,650	405,177	401,925	394,191	908,976	1,009,225	1,251,828	12,597,223		
4.	Recoverable Costs Allocated to Demand	38,999	14,303	174	21,348	75	1,393	0	1,250	1,250	1,250	12,500	17,500	110,042		
5.	Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.	Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.	Jurisdictional Energy Recoverable Costs (A)	1,835,871	2,151,757	1,372,963	938,192	1,185,468	741,650	405,177	401,925	394,191	908,976	1,009,225	1,251,828	12,597,223		
8.	Jurisdictional Demand Recoverable Costs (B)	38,999	14,303	174	21,348	75	1,393	0	1,250	1,250	1,250	12,500	17,500	110,042		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,874,870	$2,166,060	$1,373,137	$959,540	$1,185,543	$743,043	$405,177	$403,175	395,441	910,226	$1,021,725	$1,269,328	$12,707,265		

DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. PAR-3, DOCUMENT NO. 5, PAGE 1 OF 1
REVISED: 7/27/2018

Tampa Electric Company Form 42 - 6E

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

Variance Report of Capital Investment Projects - Recoverable Costs
(In Dollars)

Line		(1) Actual / Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 FGD Integration	$960,463	$1,063,216	($102,753)	-9.7%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	249,611	280,951	(31,340)	-11.2%
	c. Big Bend Unit 4 Continuous Emissions Monitors	51,105	55,016	(3,911)	-7.1%
	d. Big Bend Fuel Oil Tank No. 1 Upgrade	55,001	35,856	19,145	53.4%
	e. Big Bend Fuel Oil Tank No. 2 Upgrade	90,462	58,969	31,493	53.4%
	f. Big Bend Unit 1 Classifier Replacement	80,406	85,047	(4,641)	-5.5%
	g. Big Bend Unit 2 Classifier Replacement	58,125	61,751	(3,626)	-5.9%
	h. Big Bend Section 114 Mercury Testing Platform	8,562	9,406	(844)	-9.0%
	i. Big Bend Units 1 & 2 FGD	6,053,894	6,674,906	(621,012)	-9.3%
	j. Big Bend FGD Optimization and Utilization	1,554,567	1,712,875	(158,308)	-9.2%
	k. Big Bend NO_x Emissions Reduction	499,286	562,354	(63,068)	-11.2%
	l. Big Bend PM Minimization and Monitoring	1,809,209	1,989,614	(180,405)	-9.1%
	m. Polk NO_x Emissions Reduction	113,289	123,356	(10,067)	-8.2%
	n. Big Bend Unit 4 SOFA	198,213	218,523	(20,310)	-9.3%
	o. Big Bend Unit 1 Pre-SCR	137,625	149,608	(11,983)	-8.0%
	p. Big Bend Unit 2 Pre-SCR	130,774	142,854	(12,080)	-8.5%
	q. Big Bend Unit 3 Pre-SCR	233,143	256,173	(23,030)	-9.0%
	r. Big Bend Unit 1 SCR	7,960,376	8,698,396	(738,020)	-8.5%
	s. Big Bend Unit 2 SCR	8,407,010	9,195,158	(788,148)	-8.6%
	t. Big Bend Unit 3 SCR	6,968,871	7,628,421	(659,550)	-8.6%
	u. Big Bend Unit 4 SCR	5,420,387	5,919,666	(499,279)	-8.4%
	v. Big Bend FGD System Reliability	2,080,400	2,325,371	(244,971)	-10.5%
	w. Mercury Air Toxics Standards	824,496	928,320	(103,824)	-11.2%
	x. SO_2 Emissions Allowances	(2,601)	(3,015)	414	-13.7%
	y. Big Bend Gypsum Storage Facility	2,073,526	2,316,204	(242,678)	-10.5%
	z. CCR Rule - Phase I	130,502	224,233	(93,731)	-41.8%
	aa. CCR Rule - Phase II	2,299	0	2,299	N/A
	ab. Big Bend ELG Rule Compliance	0	0	0	N/A
	ac. Big Bend Unit 1 Section 316(b) Impingement Mortality	0	0	0	N/A
2.	Total Investment Projects - Recoverable Costs	$46,149,001	$50,713,229	($4,564,228)	-9.0%
3.	Recoverable Costs Allocated to Energy	$45,870,737	$50,394,171	($4,523,434)	-9.0%
4.	Recoverable Costs Allocated to Demand	$278,264	$319,058	($40,794)	-12.8%

Notes:

Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-2018-0014-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DOCKET NO. 20180007-EI
ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT NO. PAR-3, DOCUMENT NO. 6, PAGE 1 OF 1
REVISED: 7/27/2018

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

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line		Description (A)	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 FGD Integration	$81,171	$80,989	$80,808	$80,626	$80,445	$80,262	$79,812	$79,632	$79,450	$79,270	$79,089	$78,909	$960,463		$960,463
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	21,372	21,270	21,168	21,066	20,965	20,863	20,737	20,636	20,535	20,434	20,333	20,232	249,611		249,611
	c.	Big Bend Unit 4 Continuous Emissions Monitors	4,344	4,330	4,314	4,300	4,285	4,271	4,247	4,232	4,217	4,203	4,188	4,174	51,105		51,105
	d.	Big Bend Fuel Oil Tank No. 1 Upgrade	2,815	2,806	2,796	2,787	2,778	2,770	6,455	6,423	6,391	6,359	6,326	6,295	55,001	$55,001	
	e.	Big Bend Fuel Oil Tank No. 2 Upgrade	4,629	4,614	4,600	4,584	4,570	4,555	10,617	10,565	10,512	10,458	10,405	10,353	90,462	90,462	
	f.	Big Bend Unit 1 Classifier Replacement	6,859	6,830	6,803	6,775	6,748	6,720	6,681	6,653	6,625	6,598	6,571	6,543	80,406		80,406
	g.	Big Bend Unit 2 Classifier Replacement	4,954	4,934	4,915	4,896	4,877	4,858	4,829	4,811	4,791	4,772	4,754	4,734	58,125		58,125
	h.	Big Bend Section 114 Mercury Testing Platform	725	722	721	719	717	716	712	709	708	706	704	703	8,562		8,562
	i.	Big Bend Units 1 & 2 FGD	514,191	512,541	510,891	509,241	507,592	505,942	503,019	501,378	499,737	498,095	496,454	494,813	6,053,894		6,053,894
	j.	Big Bend FGD Optimization and Utilization	126,787	126,722	126,673	127,106	128,669	130,581	130,375	130,539	130,969	131,509	132,049	132,588	1,554,567		1,554,567
	k.	Big Bend NO_x Emissions Reduction	42,042	41,978	41,914	41,850	41,785	41,721	41,493	41,428	41,364	41,301	41,237	41,173	499,286		499,286
	l.	Big Bend PM Minimization and Monitoring	153,110	152,726	152,343	151,960	151,576	151,193	150,337	149,956	149,574	149,193	148,811	148,430	1,809,209		1,809,209
	m.	Polk NO_x Emissions Reduction	9,607	9,579	9,551	9,524	9,496	9,467	9,414	9,385	9,358	9,331	9,302	9,275	113,289		113,289
	n.	Big Bend Unit 4 SOFA	16,766	16,725	16,685	16,645	16,604	16,565	16,471	16,431	16,391	16,350	16,310	16,270	198,213		198,213
	o.	Big Bend Unit 1 Pre-SCR	11,675	11,640	11,605	11,571	11,536	11,502	11,435	11,401	11,366	11,332	11,298	11,264	137,625		137,625
	p.	Big Bend Unit 2 Pre-SCR	11,082	11,051	11,021	10,990	10,959	10,929	10,867	10,836	10,806	10,775	10,744	10,714	130,774		130,774
	q.	Big Bend Unit 3 Pre-SCR	19,734	19,684	19,634	19,583	19,533	19,484	19,373	19,324	19,273	19,224	19,173	19,124	233,143		233,143
	r.	Big Bend Unit 1 SCR	674,992	673,045	671,098	669,150	667,203	665,256	661,449	659,511	657,574	655,636	653,700	651,762	7,960,376		7,960,376
	s.	Big Bend Unit 2 SCR	712,268	710,328	708,390	706,451	704,511	702,572	698,570	696,642	694,713	692,784	690,855	688,926	8,407,010		8,407,010
	t.	Big Bend Unit 3 SCR	590,325	588,737	587,150	585,562	583,973	582,386	579,071	577,492	575,913	574,333	572,754	571,175	6,968,871		6,968,871
	u.	Big Bend Unit 4 SCR	456,706	455,523	454,342	453,169	452,014	450,873	449,747	449,981	450,214	450,449	449,273	448,096	5,420,387		5,420,387
	v.	Big Bend FGD System Reliability	175,463	175,139	174,817	174,494	174,170	173,847	172,882	172,560	172,239	171,918	171,597	171,274	2,080,400		2,080,400
	w.	Mercury Air Toxics Standards	68,615	68,478	68,407	68,337	68,454	68,315	67,997	67,921	68,879	69,836	69,698	69,559	824,496		824,496
	x.	SO_2 Emissions Allowances (B)	(218)	(218)	(218)	(217)	(217)	(217)	(216)	(216)	(216)	(216)	(216)	(216)	(2,601)		(2,601)
	y.	Big Bend Gypsum Storage Facility	174,907	174,580	174,253	173,927	173,600	173,274	172,310	171,985	171,660	171,335	171,010	170,685	2,073,526		2,073,526
	z.	CCR Rule - Phase I	6,478	6,646	6,816	6,860	6,907	6,960	8,554	10,575	14,687	17,887	18,670	19,462	130,502	130,502	
	aa.	CCR Rule - Phase II	0	0	3	7	11	21	86	202	319	434	550	666	2,299	2,299	
	ab.	Big Bend ELG Rule Compliance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	ac.	Big Bend Unit 1 Section 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
2.		Total Investment Projects - Recoverable Costs	3,891,399	3,881,399	3,871,500	3,861,963	3,853,761	3,845,686	3,837,324	3,830,992	3,828,049	3,824,306	3,815,639	3,806,983	46,149,001	$278,264	$45,870,737
3.		Recoverable Costs Allocated to Energy	3,877,477	3,867,333	3,857,285	3,847,725	3,839,495	3,831,380	3,811,612	3,803,227	3,796,140	3,789,168	3,779,688	3,770,207	45,870,737		
4.		Recoverable Costs Allocated to Demand	13,922	14,066	14,215	14,238	14,266	14,306	25,712	27,765	31,909	35,138	35,951	36,776	278,264		
5.		Retail Energy Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
6.		Retail Demand Jurisdictional Factor	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
7.		Jurisdictional Energy Recoverable Costs (C)	3,877,477	3,867,333	3,857,285	3,847,725	3,839,495	3,831,380	3,811,612	3,803,227	3,796,140	3,789,168	3,779,688	3,770,207	45,870,737		
8.		Jurisdictional Demand Recoverable Costs (D)	13,922	14,066	14,215	14,238	14,266	14,306	25,712	27,765	31,909	35,138	35,951	36,776	278,264		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$3,891,399	$3,881,399	$3,871,500	$3,861,963	$3,853,761	$3,845,686	$3,837,324	$3,830,992	$3,828,049	$3,824,306	$3,815,639	$3,806,983	$46,149,001		

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9
(B) Project's Total Return Component on Form 42-8E, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

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ECRC 2018 ACTUAL/ESTIMATED TRUE-UP
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ENVIRONMENTAL COST RECOVERY

COMMISSION FORMS

JANUARY 2019 THROUGH DECEMBER 2019

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 29
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-4

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2019 to December 2019

Form 42 - 1P

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)	$12,438,028	$124,500	$12,562,528
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	44,588,995	768,459	45,357,454
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	57,027,023	892,959	57,919,982
2. True-up for Estimated Over/(Under) Recovery for the current period January 2018 to December 2018 (Form 42-2E, Line 5 + 6 + 10)	13,373,740	98,046	13,472,483
3. Final True-up for the period January 2017 to December 2017 (Form 42-1A, Line 3)	1,482,763	15,903	1,498,666
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2019 to December 2019 (Line 1 - Line 2- Line 3)	42,170,520	779,010	42,949,530
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$42,200,883	$779,571	$42,980,454

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 to December 2019

Form 42 - 2P

O&M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 FGD Integration	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,127	$709,500		$709,500
	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	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	d. Big Bend Units 1 & 2 FGD	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,663	680,000		680,000
	e. Big Bend PM Minimization and Monitoring	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,210	33,210	398,500		398,500
	f. Big Bend NO_x Emissions Reduction	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	60,000		60,000
	g. NPDES Annual Surveillance Fees	34,500	0	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	375	425	375	375	425	450	550	550	550	175	375	375	5,000		5,000
	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	500	500	500	500	500	500	500	500	500	500	500	500	6,000		6,000
	m. Big Bend Unit 2 Pre-SCR	500	500	500	500	500	500	500	500	500	500	500	500	6,000		6,000
	n. Big Bend Unit 3 Pre-SCR	500	500	500	500	500	500	500	500	500	500	500	500	6,000		6,000
	o. Clean Water Act Section 316(b) Phase II Study	5,000	15,000	0	20,000	0	25,000	25,000	0	0	0	0	0	90,000	90,000	
	p. Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	q. Big Bend 1 SCR	0	0	10,000	22,320	0	0	0	31,140	0	93,780	10,000	0	167,240		167,240
	r. Big Bend 2 SCR	0	0	10,000	30,060	0	19,080	26,100	29,700	136,260	0	10,000	0	261,200		261,200
	s. Big Bend 3 SCR	11,700	37,960	25,000	24,660	0	30,780	16,020	21,060	43,740	111,220	59,200	15,120	396,460		396,460
	t. Big Bend 4 SCR	193,300	242,040	255,000	127,960	205,000	155,140	182,880	153,100	55,000	100,000	245,800	219,880	2,135,100		2,135,100
	u. Mercury Air Toxics Standards	0	0	7,823	55	0	6,250	10,500	9,750	10,500	9,750	10,500	9,750	74,878		74,878
	v. Greenhouse Gas Reduction Program	0	0	93,149	0	0	0	0	0	0	0	0	0	93,149		93,149
	w. Big Bend Gypsum Storage Facility (East 40)	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	1,320,000		1,320,000
	x. CCR Rule-Phase I	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	y. CCR Rule-Phase II	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	6,000,000		6,000,000
	z. Big Bend Unit 1 Section 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	aa. Big Bend ELG Rule Compliance	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	1,018,375	1,068,925	1,175,847	1,000,929	981,925	1,014,200	1,038,550	1,022,800	1,022,550	1,090,425	1,109,377	1,018,625	12,562,527	$124,500	$12,438,027
3.	Recoverable Costs Allocated to Energy	978,875	1,053,925	1,175,847	980,929	981,925	989,200	1,013,550	1,022,800	1,022,550	1,090,425	1,109,377	1,018,625	12,438,027		
4.	Recoverable Costs Allocated to Demand	39,500	15,000	0	20,000	0	25,000	25,000	0	0	0	0	0	124,500		
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)	978,875	1,053,925	1,175,847	980,929	981,925	989,200	1,013,550	1,022,800	1,022,550	1,090,425	1,109,377	1,018,625	12,438,028		
8.	Jurisdictional Demand Recoverable Costs (B)	39,500	15,000	0	20,000	0	25,000	25,000	0	0	0	0	0	124,500		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,018,375	$1,068,925	$1,175,847	$1,000,929	$981,925	$1,014,200	$1,038,550	$1,022,800	1,022,550	1,090,425	$1,109,377	$1,018,625	$12,562,528		

DOCKET NO. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-2P
EXHIBIT NO. PAR-4 , DOCUMENT NO. 2

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 to December 2019

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	$78,728	$78,547	$78,366	$78,186	$78,005	$77,825	$77,643	$77,463	$77,282	$77,102	$76,921	$76,740	$932,808		$932,808
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	20,131	20,030	19,929	19,827	19,725	19,624	19,523	19,422	19,321	19,220	19,119	19,018	234,889		234,889
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	4,160	4,145	4,130	4,116	4,102	4,087	4,073	4,059	4,043	4,029	4,015	4,000	48,959		48,959
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4	6,263	6,231	6,198	6,166	6,135	6,102	6,070	6,038	6,005	5,974	5,942	5,909	73,033	$73,033	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	5	10,300	10,247	10,194	10,142	10,089	10,036	9,983	9,931	9,878	9,825	9,772	9,720	120,117	120,117	
	f.	Big Bend Unit 1 Classifier Replacement	6	6,516	6,488	6,461	6,433	6,406	6,378	6,351	6,323	6,296	6,268	6,240	6,213	76,373		76,373
	g.	Big Bend Unit 2 Classifier Replacement	7	4,715	4,697	4,677	4,658	4,638	4,620	4,601	4,581	4,563	4,544	4,524	4,506	55,324		55,324
	h.	Big Bend Section 114 Mercury Testing Platform	8	700	699	696	695	693	691	690	687	686	684	682	681	8,284		8,284
	i.	Big Bend Units 1 & 2 FGD	9	493,173	491,532	489,890	488,249	486,608	484,967	483,326	481,685	480,043	478,402	476,761	475,120	5,809,756		5,809,756
	j.	Big Bend FGD Optimization and Utilization	10	133,093	132,750	132,450	132,151	131,850	131,550	131,249	130,950	130,649	130,349	130,050	129,749	1,576,840		1,576,840
	k.	Big Bend NO_x Emissions Reduction	11	41,109	41,046	40,981	40,918	40,854	40,790	40,726	40,662	40,599	40,535	40,471	40,407	489,098		489,098
	l.	Big Bend PM Minimization and Monitoring	12	148,048	147,667	147,286	146,904	146,523	146,141	145,760	145,378	144,997	144,615	144,234	143,853	1,751,406		1,751,406
	m.	Polk NO_x Emissions Reduction	13	9,247	9,219	9,192	9,164	9,136	9,108	9,081	9,053	9,025	8,998	8,970	8,942	109,135		109,135
	n.	Big Bend Unit 4 SOFA	14	16,230	16,190	16,150	16,110	16,069	16,029	15,989	15,950	15,910	15,870	15,830	15,790	192,117		192,117
	o.	Big Bend Unit 1 Pre-SCR	15	11,229	11,194	11,160	11,125	11,092	11,057	11,022	10,988	10,953	10,919	10,884	10,850	132,473		132,473
	p.	Big Bend Unit 2 Pre-SCR	16	10,683	10,653	10,622	10,591	10,561	10,530	10,500	10,469	10,438	10,408	10,377	10,347	126,179		126,179
	q.	Big Bend Unit 3 Pre-SCR	17	19,074	19,024	18,975	18,925	18,875	18,825	18,776	18,725	18,676	18,625	18,576	18,526	225,602		225,602
	r.	Big Bend Unit 1 SCR	18	641,285	639,349	637,412	635,474	633,538	631,600	629,663	627,725	625,789	623,851	621,914	619,977	7,567,577		7,567,577
	s.	Big Bend Unit 2 SCR	19	718,180	697,994	696,037	694,080	692,122	690,165	688,208	686,251	684,293	682,336	680,379	678,421	8,288,466		8,288,466
	t.	Big Bend Unit 3 SCR	20	569,595	568,016	566,436	564,856	563,277	561,698	560,118	558,539	556,960	555,379	553,800	552,221	6,730,895		6,730,895
	u.	Big Bend Unit 4 SCR	21	446,920	445,744	444,796	445,682	448,170	449,683	451,191	451,845	450,669	449,493	448,317	447,140	5,379,650		5,379,650
	v.	Big Bend FGD System Reliability	22	170,953	170,632	170,310	169,989	169,667	169,345	169,024	168,703	168,382	168,059	167,738	167,417	2,030,219		2,030,219
	w.	Mercury Air Toxics Standards	23	68,379	67,144	67,004	66,865	66,727	66,666	66,605	66,466	66,327	66,188	66,832	67,476	802,679		802,679
	x.	SO_2 Emissions Allowances (B)	24	(248)	(203)	(203)	(248)	(203)	(203)	(248)	(203)	(203)	(248)	(203)	(203)	(2,616)		(2,616)
	y.	Big Bend Gypsum Storage Facility	25	170,360	170,035	169,711	169,385	169,060	168,735	168,410	168,085	167,760	167,435	167,110	166,784	2,022,870		2,022,870
	z.	CCR-Phase I	26	16,509	17,479	19,035	19,808	19,798	19,787	19,776	19,766	19,755	19,902	22,398	27,087	241,100	241,100	
	aa.	CCR-Phase II	27	1,038	1,554	1,961	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	24,047	24,047	
	ab.	Big Bend ELG Rule Compliance	28	940	940	940	940	940	940	940	940	940	940	940	940	11,280	11,280	
	ac.	Big Bend Unit 1 Section 316(b) Impingement Mort	29	16,292	17,858	19,424	20,991	22,557	24,123	25,690	27,257	28,823	30,389	31,956	33,522	298,882	298,882	
2.		Total Investment Projects - Recoverable Costs		3,833,602	3,806,901	3,800,220	3,794,348	3,789,180	3,783,065	3,776,906	3,769,904	3,761,025	3,752,257	3,746,715	3,743,319	45,357,442	$768,459	$44,588,983
3.		Recoverable Costs Allocated to Energy		3,782,260	3,752,592	3,742,468	3,734,135	3,727,495	3,719,911	3,712,281	3,703,806	3,693,458	3,683,061	3,673,541	3,663,975	44,588,983		44,588,983
4.		Recoverable Costs Allocated to Demand		51,342	54,309	57,752	60,213	61,685	63,154	64,625	66,098	67,567	69,196	73,174	79,344	768,459	768,459	
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)		3,782,260	3,752,592	3,742,468	3,734,135	3,727,495	3,719,911	3,712,281	3,703,806	3,693,458	3,683,061	3,673,541	3,663,975	44,588,995		
8.		Jurisdictional Demand Recoverable Costs (D)		51,342	54,309	57,752	60,213	61,685	63,154	64,625	66,098	67,567	69,196	73,174	79,344	768,459		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$3,833,602	$3,806,901	$3,800,220	$3,794,348	$3,789,180	$3,783,065	$3,776,906	$3,769,904	$3,761,025	$3,752,257	$3,746,715	$3,743,319	$45,357,454		

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. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-3P
EXHIBIT NO. PAR-4 , DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 to December 2019

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)	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	$13,763,081	
3.	Less: Accumulated Depreciation	(5,786,332)	(5,815,169)	(5,844,006)	(5,872,843)	(5,901,680)	(5,930,517)	(5,959,354)	(5,988,191)	(6,017,028)	(6,045,865)	(6,074,702)	(6,103,539)	(6,132,376)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,976,749	7,947,912	7,919,075	7,890,238	7,861,401	7,832,564	7,803,727	7,774,890	7,746,053	7,717,216	7,688,379	7,659,542	7,630,705	
6.	Average Net Investment		7,962,331	7,933,494	7,904,657	7,875,820	7,846,983	7,818,146	7,789,309	7,760,472	7,731,635	7,702,798	7,673,961	7,645,124	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$38,515	$38,376	$38,236	$38,097	$37,957	$37,818	$37,678	$37,539	$37,399	$37,260	$37,120	$36,981	$452,976
	b. Debt Component Grossed Up For Taxes (C)		11,376	11,334	11,293	11,252	11,211	11,170	11,128	11,087	11,046	11,005	10,964	10,922	133,788
8.	Investment Expenses														
	a. Depreciation (D)		$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$28,837	$346,044
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		$78,728	$78,547	$78,366	$78,186	$78,005	$77,825	$77,643	$77,463	$77,282	$77,102	$76,921	$76,740	$932,808
	a. Recoverable Costs Allocated to Energy		78,728	78,547	78,366	78,186	78,005	77,825	77,643	77,463	77,282	77,102	76,921	76,740	932,808
	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)		78,728	78,547	78,366	78,186	78,005	77,825	77,643	77,463	77,282	77,102	76,921	76,740	932,808
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)		$78,728	$78,547	$78,366	$78,186	$78,005	$77,825	$77,643	$77,463	$77,282	$77,102	$76,921	$76,740	$932,808

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($13,435,775) and 315.45 ($327,307)
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% x 1/12.
(D) Applicable depreciation rates are 2.5% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-4P
EXHIBIT NO. PAR-4, DOCUMENT NO. 4, PAGE 1 OF 29

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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	(4,372,970)	(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)		$3,080	$3,002	$2,924	$2,846	$2,767	$2,689	$2,611	$2,533	$2,455	$2,377	$2,299	$2,221	$31,804
	b. Debt Component Grossed Up For Taxes (C)		910	887	864	840	817	794	771	748	725	702	679	656	9,393
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)		$20,131	$20,030	$19,929	$19,827	$19,725	$19,624	$19,523	$19,422	$19,321	$19,220	$19,119	$19,018	$234,889
	a. Recoverable Costs Allocated to Energy		20,131	20,030	19,929	19,827	19,725	19,624	19,523	19,422	19,321	19,220	19,119	19,018	234,889
	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)		20,131	20,030	19,929	19,827	19,725	19,624	19,523	19,422	19,321	19,220	19,119	19,018	234,889
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)		$20,131	$20,030	$19,929	$19,827	$19,725	$19,624	$19,523	$19,422	$19,321	$19,220	$19,119	$19,018	$234,889

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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

DOCKET NO. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-4P
EXHIBIT NO. PAR-4, DOCUMENT NO. 4, PAGE 2 OF 29

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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	(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)		$1,428	$1,417	$1,405	$1,394	$1,383	$1,372	$1,361	$1,350	$1,338	$1,327	$1,316	$1,305	$16,396
	b. Debt Component Grossed Up For Taxes (C)		422	418	415	412	409	405	402	399	395	392	389	385	4,843
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)		$4,160	$4,145	$4,130	$4,116	$4,102	$4,087	$4,073	$4,059	$4,043	$4,029	$4,015	$4,000	$48,959
	a. Recoverable Costs Allocated to Energy		4,160	4,145	4,130	4,116	4,102	4,087	4,073	4,059	4,043	4,029	4,015	4,000	48,959
	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)		4,160	4,145	4,130	4,116	4,102	4,087	4,073	4,059	4,043	4,029	4,015	4,000	48,959
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)		$4,160	$4,145	$4,130	$4,116	$4,102	$4,087	$4,073	$4,059	$4,043	$4,029	$4,015	$4,000	$48,959

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% x 1/12.
(D) Applicable depreciation rate is 3.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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	(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)		$880	$855	$830	$805	$781	$756	$731	$706	$681	$657	$632	$607	$8,921
	b. Debt Component Grossed Up For Taxes (C)		260	253	245	238	231	223	216	209	201	194	187	179	2,636
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)		$6,263	$6,231	$6,198	$6,166	$6,135	$6,102	$6,070	$6,038	$6,005	$5,974	$5,942	$5,909	$73,033
	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		6,263	6,231	6,198	6,166	6,135	6,102	6,070	6,038	6,005	5,974	5,942	5,909	73,033
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	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)		6,263	6,231	6,198	6,166	6,135	6,102	6,070	6,038	6,005	5,974	5,942	5,909	73,033
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,263	$6,231	$6,198	$6,166	$6,135	$6,102	$6,070	$6,038	$6,005	$5,974	$5,942	$5,909	$73,033

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% x 1/12.
(D) Applicable depreciation rate through June 2018 was 3.4%; depreciation was accelerated to 12.36% as of July 2018.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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	(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)		$1,447	$1,406	$1,365	$1,325	$1,284	$1,243	$1,202	$1,162	$1,121	$1,080	$1,039	$999	$14,673
	b. Debt Component Grossed Up For Taxes (C)		427	415	403	391	379	367	355	343	331	319	307	295	4,332
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)		$10,300	$10,247	$10,194	$10,142	$10,089	$10,036	$9,983	$9,931	$9,878	$9,825	$9,772	$9,720	$120,117
	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		10,300	10,247	10,194	10,142	10,089	10,036	9,983	9,931	9,878	9,825	9,772	9,720	120,117
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	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)		10,300	10,247	10,194	10,142	10,089	10,036	9,983	9,931	9,878	9,825	9,772	9,720	120,117
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,300	$10,247	$10,194	$10,142	$10,089	$10,036	$9,983	$9,931	$9,878	$9,825	$9,772	$9,720	$120,117

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% x 1/12.
(D) Applicable depreciation rate through June 2018 was 3.4%; depreciation was accelerated to 12.35% as of July 2018.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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	(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)		$1,643	$1,621	$1,600	$1,579	$1,558	$1,536	$1,515	$1,494	$1,473	$1,451	$1,430	$1,409	$18,309
	b. Debt Component Grossed Up For Taxes (C)		485	479	473	466	460	454	448	441	435	429	422	416	5,408
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)		$6,516	$6,488	$6,461	$6,433	$6,406	$6,378	$6,351	$6,323	$6,296	$6,268	$6,240	$6,213	$76,373
	a. Recoverable Costs Allocated to Energy		6,516	6,488	6,461	6,433	6,406	6,378	6,351	6,323	6,296	6,268	6,240	6,213	76,373
	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)		6,516	6,488	6,461	6,433	6,406	6,378	6,351	6,323	6,296	6,268	6,240	6,213	76,373
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)		$6,516	$6,488	$6,461	$6,433	$6,406	$6,378	$6,351	$6,323	$6,296	$6,268	$6,240	$6,213	$76,373

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 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	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	(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)		$1,296	$1,282	$1,267	$1,252	$1,237	$1,223	$1,208	$1,193	$1,179	$1,164	$1,149	$1,135	$14,585
	b. Debt Component Grossed Up For Taxes (C)		383	379	374	370	365	361	357	352	348	344	339	335	4,307
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)		$4,715	$4,697	$4,677	$4,658	$4,638	$4,620	$4,601	$4,581	$4,563	$4,544	$4,524	$4,506	$55,324
	a. Recoverable Costs Allocated to Energy		4,715	4,697	4,677	4,658	4,638	4,620	4,601	4,581	4,563	4,544	4,524	4,506	55,324
	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)		4,715	4,697	4,677	4,658	4,638	4,620	4,601	4,581	4,563	4,544	4,524	4,506	55,324
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)		$4,715	$4,697	$4,677	$4,658	$4,638	$4,620	$4,601	$4,581	$4,563	$4,544	$4,524	$4,506	$55,324

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 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	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	(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)		$315	$314	$312	$311	$310	$308	$307	$305	$304	$303	$301	$300	$3,690
	b. Debt Component Grossed Up For Taxes (C)		93	93	92	92	91	91	91	90	90	89	89	89	1,090
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)		$700	$699	$696	$695	$693	$691	$690	$687	$686	$684	$682	$681	$8,284
	a. Recoverable Costs Allocated to Energy		700	699	696	695	693	691	690	687	686	684	682	681	8,284
	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)		700	699	696	695	693	691	690	687	686	684	682	681	8,284
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)		$700	$699	$696	$695	$693	$691	$690	$687	$686	$684	$682	$681	$8,284

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 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	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	(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)		$178,526	$177,259	$175,992	$174,725	$173,458	$172,191	$170,924	$169,657	$168,390	$167,123	$165,856	$164,589	$2,058,690
	b. Debt Component Grossed Up For Taxes (C)		52,728	52,354	51,979	51,605	51,231	50,857	50,483	50,109	49,734	49,360	48,986	48,612	608,038
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)		$493,173	$491,532	$489,890	$488,249	$486,608	$484,967	$483,326	$481,685	$480,043	$478,402	$476,761	$475,120	$5,809,756
	a. Recoverable Costs Allocated to Energy		493,173	491,532	489,890	488,249	486,608	484,967	483,326	481,685	480,043	478,402	476,761	475,120	5,809,756
	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)		493,173	491,532	489,890	488,249	486,608	484,967	483,326	481,685	480,043	478,402	476,761	475,120	5,809,756
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)		$493,173	$491,532	$489,890	$488,249	$486,608	$484,967	$483,326	$481,685	$480,043	$478,402	$476,761	$475,120	$5,809,756

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.46 ($94,929,061), 312.45 ($105,398) & 315.46 ($220,782)
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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		100,000	0	0	0	0	0	0	0	0	0	0	0	100,000
	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)	$22,860,364	$22,960,364	$22,960,364	$22,960,364	$22,960,364	$22,960,364	$22,960,364	$22,960,364	$22,960,364	$22,960,364	$22,960,364	$22,960,364	$22,960,364	
3.	Less: Accumulated Depreciation	(9,346,870)	(9,394,813)	(9,442,714)	(9,490,615)	(9,538,516)	(9,586,417)	(9,634,318)	(9,682,219)	(9,730,120)	(9,778,021)	(9,825,922)	(9,873,823)	(9,921,724)	
4.	CWIP - Non-Interest Bearing	100,000	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$13,613,494	13,565,551	13,517,650	13,469,749	13,421,848	13,373,947	13,326,046	13,278,145	13,230,244	13,182,343	13,134,442	13,086,541	13,038,640	
6.	Average Net Investment		13,589,522	13,541,600	13,493,699	13,445,798	13,397,897	13,349,996	13,302,095	13,254,194	13,206,293	13,158,392	13,110,491	13,062,590	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$65,735	$65,503	$65,271	$65,040	$64,808	$64,576	$64,344	$64,113	$63,881	$63,649	$63,418	$63,186	$773,524
	b. Debt Component Grossed Up For Taxes (C)		19,415	19,346	19,278	19,210	19,141	19,073	19,004	18,936	18,867	18,799	18,731	18,662	228,462
8.	Investment Expenses														
	a. Depreciation (D)		$47,943	$47,901	$47,901	$47,901	$47,901	$47,901	$47,901	$47,901	$47,901	$47,901	$47,901	$47,901	$574,854
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		$133,093	$132,750	$132,450	$132,151	$131,850	$131,550	$131,249	$130,950	$130,649	$130,349	$130,050	$129,749	$1,576,840
	a. Recoverable Costs Allocated to Energy		133,093	132,750	132,450	132,151	131,850	131,550	131,249	130,950	130,649	130,349	130,050	129,749	1,576,840
	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)		133,093	132,750	132,450	132,151	131,850	131,550	131,249	130,950	130,649	130,349	130,050	129,749	1,576,840
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)		$133,093	$132,750	$132,450	$132,151	$131,850	$131,550	$131,249	$130,950	$130,649	$130,349	$130,050	$129,749	$1,576,840

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.45 ($22,835,587), 311.45 ($39,818), 316.40 ($36,254), 315.45 ($220), 312.46 ($47,047), and 312.24 ($1,438)
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% x 1/12.
(D) Applicable depreciation rates are 2.5%, 2.0%, 4.2%, 3.1%, 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 the Projected Period Amount
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	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	1,749,771	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)		$23,874	$23,825	$23,775	$23,726	$23,677	$23,628	$23,578	$23,529	$23,480	$23,431	$23,381	$23,332	$283,236
	b. Debt Component Grossed Up For Taxes (C)		7,051	7,037	7,022	7,008	6,993	6,978	6,964	6,949	6,935	6,920	6,906	6,891	83,654
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)		$41,109	$41,046	$40,981	$40,918	$40,854	$40,790	$40,726	$40,662	$40,599	$40,535	$40,471	$40,407	$489,098
	a. Recoverable Costs Allocated to Energy		41,109	41,046	40,981	40,918	40,854	40,790	40,726	40,662	40,599	40,535	40,471	40,407	489,098
	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)		41,109	41,046	40,981	40,918	40,854	40,790	40,726	40,662	40,599	40,535	40,471	40,407	489,098
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)		$41,109	$41,046	$40,981	$40,918	$40,854	$40,790	$40,726	$40,662	$40,599	$40,535	$40,471	$40,407	$489,098

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 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend 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	(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)		$67,299	$67,005	$66,711	$66,416	$66,122	$65,827	$65,533	$65,238	$64,944	$64,649	$64,355	$64,061	$788,160
	b. Debt Component Grossed Up For Taxes (C)		19,877	19,790	19,703	19,616	19,529	19,442	19,355	19,268	19,181	19,094	19,007	18,920	232,782
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)		$148,048	$147,667	$147,286	$146,904	$146,523	$146,141	$145,760	$145,378	$144,997	$144,615	$144,234	$143,853	$1,751,406
	a. Recoverable Costs Allocated to Energy		148,048	147,667	147,286	146,904	146,523	146,141	145,760	145,378	144,997	144,615	144,234	143,853	1,751,406
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		148,048	147,667	147,286	146,904	146,523	146,141	145,760	145,378	144,997	144,615	144,234	143,853	1,751,406
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$148,048	$147,667	$147,286	$146,904	$146,523	$146,141	$145,760	$145,378	$144,997	$144,615	$144,234	$143,853	$1,751,406

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 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 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	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	(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)		$3,723	$3,702	$3,681	$3,659	$3,638	$3,616	$3,595	$3,574	$3,552	$3,531	$3,509	$3,488	$43,268
	b. Debt Component Grossed Up For Taxes (C)		1,100	1,093	1,087	1,081	1,074	1,068	1,062	1,055	1,049	1,043	1,037	1,030	12,779
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)		$9,247	$9,219	$9,192	$9,164	$9,136	$9,108	$9,081	$9,053	$9,025	$8,998	$8,970	$8,942	$109,135
	a. Recoverable Costs Allocated to Energy		9,247	9,219	9,192	9,164	9,136	9,108	9,081	9,053	9,025	8,998	8,970	8,942	109,135
	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)		9,247	9,219	9,192	9,164	9,136	9,108	9,081	9,053	9,025	8,998	8,970	8,942	109,135
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)		$9,247	$9,219	$9,192	$9,164	$9,136	$9,108	$9,081	$9,053	$9,025	$8,998	$8,970	$8,942	$109,135

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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	(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)		$7,591	$7,560	$7,529	$7,498	$7,467	$7,436	$7,405	$7,375	$7,344	$7,313	$7,282	$7,251	$89,051
	b. Debt Component Grossed Up For Taxes (C)		2,242	2,233	2,224	2,215	2,205	2,196	2,187	2,178	2,169	2,160	2,151	2,142	26,302
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)		$16,230	$16,190	$16,150	$16,110	$16,069	$16,029	$15,989	$15,950	$15,910	$15,870	$15,830	$15,790	$192,117
	a. Recoverable Costs Allocated to Energy		16,230	16,190	16,150	16,110	16,069	16,029	15,989	15,950	15,910	15,870	15,830	15,790	192,117
	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)		16,230	16,190	16,150	16,110	16,069	16,029	15,989	15,950	15,910	15,870	15,830	15,790	192,117
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)		$16,230	$16,190	$16,150	$16,110	$16,069	$16,029	$15,989	$15,950	$15,910	$15,870	$15,830	$15,790	$192,117

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 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	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	(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)		$4,425	$4,398	$4,372	$4,345	$4,319	$4,292	$4,265	$4,239	$4,212	$4,186	$4,159	$4,132	$51,344
	b. Debt Component Grossed Up For Taxes (C)		1,307	1,299	1,291	1,283	1,276	1,268	1,260	1,252	1,244	1,236	1,228	1,221	15,165
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)		$11,229	$11,194	$11,160	$11,125	$11,092	$11,057	$11,022	$10,988	$10,953	$10,919	$10,884	$10,850	$132,473
	a. Recoverable Costs Allocated to Energy		11,229	11,194	11,160	11,125	11,092	11,057	11,022	10,988	10,953	10,919	10,884	10,850	132,473
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		11,229	11,194	11,160	11,125	11,092	11,057	11,022	10,988	10,953	10,919	10,884	10,850	132,473
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$11,229	$11,194	$11,160	$11,125	$11,092	$11,057	$11,022	$10,988	$10,953	$10,919	$10,884	$10,850	$132,473

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 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	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	(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)		$4,482	$4,459	$4,435	$4,411	$4,388	$4,364	$4,341	$4,317	$4,293	$4,270	$4,246	$4,223	$52,229
	b. Debt Component Grossed Up For Taxes (C)		1,324	1,317	1,310	1,303	1,296	1,289	1,282	1,275	1,268	1,261	1,254	1,247	15,426
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)		$10,683	$10,653	$10,622	$10,591	$10,561	$10,530	$10,500	$10,469	$10,438	$10,408	$10,377	$10,347	$126,179
	a. Recoverable Costs Allocated to Energy		10,683	10,653	10,622	10,591	10,561	10,530	10,500	10,469	10,438	10,408	10,377	10,347	126,179
	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)		10,683	10,653	10,622	10,591	10,561	10,530	10,500	10,469	10,438	10,408	10,377	10,347	126,179
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)		$10,683	$10,653	$10,622	$10,591	$10,561	$10,530	$10,500	$10,469	$10,438	$10,408	$10,377	$10,347	$126,179

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 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	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	(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)		$8,585	$8,547	$8,509	$8,470	$8,432	$8,393	$8,355	$8,316	$8,278	$8,239	$8,201	$8,162	$100,487
	b. Debt Component Grossed Up For Taxes (C)		2,536	2,524	2,513	2,502	2,490	2,479	2,468	2,456	2,445	2,433	2,422	2,411	29,679
8.	Investment Expenses														
	a. Depreciation (D)		$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$7,953	$95,436
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		$19,074	$19,024	$18,975	$18,925	$18,875	$18,825	$18,776	$18,725	$18,676	$18,625	$18,576	$18,526	$225,602
	a. Recoverable Costs Allocated to Energy		19,074	19,024	18,975	18,925	18,875	18,825	18,776	18,725	18,676	18,625	18,576	18,526	225,602
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		19,074	19,024	18,975	18,925	18,875	18,825	18,776	18,725	18,676	18,625	18,576	18,526	225,602
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$19,074	$19,024	$18,975	$18,925	$18,875	$18,825	$18,776	$18,725	$18,676	$18,625	$18,576	$18,526	$225,602

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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

DOCKET NO. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-4P
EXHIBIT NO. PAR-4, DOCUMENT NO. 4, PAGE 17 OF 29

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	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	(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 (B)	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 (C)		$256,393	$254,898	$253,403	$251,907	$250,412	$248,916	$247,421	$245,925	$244,430	$242,934	$241,439	$239,943	$2,978,021
	b. Debt Component Grossed Up For Taxes (D)		75,726	75,285	74,843	74,401	73,960	73,518	73,076	72,634	72,193	71,751	71,309	70,868	879,564
8.	Investment Expenses														
	a. Depreciation (E)		$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)		$641,285	$639,349	$637,412	$635,474	$633,538	$631,600	$629,663	$627,725	$625,789	$623,851	$621,914	$619,977	$7,567,577
	a. Recoverable Costs Allocated to Energy		641,285	639,349	637,412	635,474	633,538	631,600	629,663	627,725	625,789	623,851	621,914	619,977	7,567,577
	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 (F)		641,285	639,349	637,412	635,474	633,538	631,600	629,663	627,725	625,789	623,851	621,914	619,977	7,567,577
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)		$641,285	$639,349	$637,412	$635,474	$633,538	$631,600	$629,663	$627,725	$625,789	$623,851	$621,914	$619,977	$7,567,577

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) Beginning CWIP balance of $1,362, 824 has been moved to from Big Bent Unit 1 SCR to Big Bend Unit 2 SCR as it relates to that project.
(C) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(D) Line 6 x 1.7144% x 1/12.
(E) Applicable depreciation rate is 4.1%, 4.3%, 4.8%, and 4.1%
(F) Line 9a x Line 10
(G) Line 9b x Line 11

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ECRC 2019 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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		1,362,824	0	0	0	0	0	0	0	0	0	0	0	1,362,824
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$95,175,309	$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	(34,508,540)	(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 (B)	1,362,824	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$62,029,593	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		61,864,318	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 (C)		$299,248	$297,693	$296,182	$294,671	$293,160	$291,649	$290,138	$288,627	$287,116	$285,605	$284,094	$282,583	$3,490,766
	b. Debt Component Grossed Up For Taxes (D)		88,383	87,924	87,478	87,032	86,585	86,139	85,693	85,247	84,800	84,354	83,908	83,461	1,031,004
8.	Investment Expenses														
	a. Depreciation (E)		330,549	$312,377	$312,377	$312,377	$312,377	$312,377	$312,377	$312,377	$312,377	$312,377	$312,377	$312,377	$3,766,696
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		$718,180	$697,994	$696,037	$694,080	$692,122	$690,165	$688,208	$686,251	$684,293	$682,336	$680,379	$678,421	$8,288,466
	a. Recoverable Costs Allocated to Energy		718,180	697,994	696,037	694,080	692,122	690,165	688,208	686,251	684,293	682,336	680,379	678,421	8,288,466
	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 (F)		718,180	697,994	696,037	694,080	692,122	690,165	688,208	686,251	684,293	682,336	680,379	678,421	8,288,466
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)		$718,180	$697,994	$696,037	$694,080	$692,122	$690,165	$688,208	$686,251	$684,293	$682,336	$680,379	$678,421	$8,288,466

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) Beginning CWIP balance of $1,362, 824 has been moved to from Big Bent Unit 1 SCR to Big Bend Unit 2 SCR as it relates to that project.
(C) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(D) Line 6 x 1.7144% x 1/12.
(E) Applicable depreciation rates are 3.5%, 4.0%, 4.1%, and 3.7%.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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	(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)		$245,123	$243,904	$242,685	$241,465	$240,246	$239,027	$237,807	$236,588	$235,369	$234,149	$232,930	$231,711	$2,861,004
	b. Debt Component Grossed Up For Taxes (C)		72,398	72,038	71,677	71,317	70,957	70,597	70,237	69,877	69,517	69,156	68,796	68,436	845,003
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)		$569,595	$568,016	$566,436	$564,856	$563,277	$561,698	$560,118	$558,539	$556,960	$555,379	$553,800	$552,221	$6,730,895
	a. Recoverable Costs Allocated to Energy		569,595	568,016	566,436	564,856	563,277	561,698	560,118	558,539	556,960	555,379	553,800	552,221	6,730,895
	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)		569,595	568,016	566,436	564,856	563,277	561,698	560,118	558,539	556,960	555,379	553,800	552,221	6,730,895
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)		$569,595	$568,016	$566,436	$564,856	$563,277	$561,698	$560,118	$558,539	$556,960	$555,379	$553,800	$552,221	$6,730,895

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 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 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	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	$73,000	$585,000	$585,000	$273,000	$584,000	$0	$0	$0	$0	$0	$2,100,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	3,016,335	3,016,335
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$65,312,581	$68,328,915	
3.	Less: Accumulated Depreciation	($24,766,293)	(24,954,003)	(25,141,713)	(25,329,423)	(25,517,133)	(25,704,843)	(25,892,553)	(26,080,263)	(26,267,973)	(26,455,683)	(26,643,393)	(26,831,103)	(27,018,813)	
4.	CWIP - Non-Interest Bearing	$916,335	916,335	916,335	989,335	1,574,335	2,159,335	2,432,335	3,016,335	3,016,335	3,016,335	3,016,335	3,016,335	0	
5.	Net Investment (Lines 2 + 3 + 4)	$41,462,622	41,274,912	41,087,202	40,972,492	41,369,782	41,767,072	41,852,362	42,248,652	42,060,942	41,873,232	41,685,522	41,497,812	41,310,102	
6.	Average Net Investment		41,368,767	41,181,057	41,029,847	41,171,137	41,568,427	41,809,717	42,050,507	42,154,797	41,967,087	41,779,377	41,591,667	41,403,957	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$200,108	$199,200	$198,468	$199,152	$201,073	$202,241	$203,405	$203,910	$203,002	$202,094	$201,186	$200,278	$2,414,117
	b. Debt Component Grossed Up For Taxes (C)		59,102	58,834	58,618	58,820	59,387	59,732	60,076	60,225	59,957	59,689	59,421	59,152	713,013
8.	Investment Expenses														
	a. Depreciation (D)		$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$187,710	$2,252,520
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		$446,920	$445,744	$444,796	$445,682	$448,170	$449,683	$451,191	$451,845	$450,669	$449,493	$448,317	$447,140	$5,379,650
	a. Recoverable Costs Allocated to Energy		446,920	445,744	444,796	445,682	448,170	449,683	451,191	451,845	450,669	449,493	448,317	447,140	5,379,650
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		446,920	445,744	444,796	445,682	448,170	449,683	451,191	451,845	450,669	449,493	448,317	447,140	5,379,650
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$446,920	$445,744	$444,796	$445,682	$448,170	$449,683	$451,191	$451,845	$450,669	$449,493	$448,317	$447,140	$5,379,650

Notes:

(A) Applicable depreciable base for Big Bend; account 311.54 ($16,857,250), 312.54 ($36,567,266), 315.54 ($10,642,027), 316.54 ($687,934), 315.40 ($558,103), and 312.44 ($3,016,335)
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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

DOCKET NO. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-4P
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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)	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	$24,336,707	
3.	Less: Accumulated Depreciation	(5,216,370)	(5,267,679)	(5,318,988)	(5,370,297)	(5,421,606)	(5,472,915)	(5,524,224)	(5,575,533)	(5,626,842)	(5,678,151)	(5,729,460)	(5,780,769)	(5,832,078)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$19,120,337	19,069,028	19,017,719	18,966,410	18,915,101	18,863,792	18,812,483	18,761,174	18,709,865	18,658,556	18,607,247	18,555,938	18,504,629	
6.	Average Net Investment		19,094,683	19,043,374	18,992,065	18,940,756	18,889,447	18,838,138	18,786,829	18,735,520	18,684,211	18,632,902	18,581,593	18,530,284	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$92,364	$92,116	$91,868	$91,620	$91,371	$91,123	$90,875	$90,627	$90,379	$90,130	$89,882	$89,634	$1,091,989
	b. Debt Component Grossed Up For Taxes (C)		27,280	27,207	27,133	27,060	26,987	26,913	26,840	26,767	26,694	26,620	26,547	26,474	322,522
8.	Investment Expenses														
	a. Depreciation (D)		$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$51,309	$615,708
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		$170,953	$170,632	$170,310	$169,989	$169,667	$169,345	$169,024	$168,703	$168,382	$168,059	$167,738	$167,417	$2,030,219
	a. Recoverable Costs Allocated to Energy		170,953	170,632	170,310	169,989	169,667	169,345	169,024	168,703	168,382	168,059	167,738	167,417	2,030,219
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		170,953	170,632	170,310	169,989	169,667	169,345	169,024	168,703	168,382	168,059	167,738	167,417	2,030,219
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$170,953	$170,632	$170,310	$169,989	$169,667	$169,345	$169,024	$168,703	$168,382	$168,059	$167,738	$167,417	$2,030,219

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45 ($22,880,499) and 312.44 ($1,456,209).
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% x 1/12.
(D) Applicable depreciation rate is 2.5% and 3.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
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	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 (A)		($350,000)	$0	$0	$0	$0	$25,000	$0	$0	$0	$0	$250,000	$0	($75,000)
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	275,000	275,000
	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 (B)	$8,627,974	8,627,974	8,627,974	8,627,974	8,627,974	8,627,974	8,627,974	8,627,974	8,627,974	8,627,974	8,627,974	8,627,974	8,902,974	
3.	Less: Accumulated Depreciation	($1,420,316)	(1,442,506)	(1,464,696)	(1,486,886)	(1,509,076)	(1,531,266)	(1,553,456)	(1,575,646)	(1,597,836)	(1,620,026)	(1,642,216)	(1,664,406)	(1,686,596)	
4.	CWIP - Non-Interest Bearing	$350,000	0	0	0	0	0	25,000	25,000	25,000	25,000	25,000	275,000	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,557,658	7,185,468	7,163,278	7,141,088	7,118,898	7,096,708	7,099,518	7,077,328	7,055,138	7,032,948	7,010,758	7,238,568	7,216,378	
6.	Average Net Investment		7,371,563	7,174,373	7,152,183	7,129,993	7,107,803	7,098,113	7,088,423	7,066,233	7,044,043	7,021,853	7,124,663	7,227,473	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		$35,657	$34,704	$34,596	$34,489	$34,382	$34,335	$34,288	$34,181	$34,073	$33,966	$34,463	$34,960	$414,094
	b. Debt Component Grossed Up For Taxes (D)		10,532	10,250	10,218	10,186	10,155	10,141	10,127	10,095	10,064	10,032	10,179	10,326	122,305
8.	Investment Expenses														
	a. Depreciation (E)		22,190	22,190	22,190	22,190	22,190	22,190	22,190	22,190	22,190	22,190	22,190	22,190	$266,280
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		$68,379	$67,144	$67,004	$66,865	$66,727	$66,666	$66,605	$66,466	$66,327	$66,188	$66,832	$67,476	$802,679
	a. Recoverable Costs Allocated to Energy		68,379	67,144	67,004	66,865	66,727	66,666	66,605	66,466	66,327	66,188	66,832	67,476	802,679
	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 (F)		68,379	67,144	67,004	66,865	66,727	66,666	66,605	66,466	66,327	66,188	66,832	67,476	802,679
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)		$68,379	$67,144	$67,004	$66,865	$66,727	$66,666	$66,605	$66,466	$66,327	$66,188	$66,832	$67,476	$802,679

Notes:

(A) $350,000 of expenditures included in CWIP for the 2018 Actual/Estimate will not be spent until later in 2019 and 2020.
(B) 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 ($291,035), 315.45
(C) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(D) Line 6 x 1.7144% x 1/12.
(E) 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%
(F) Line 9a x Line 10
(G) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 to December 2019

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	(34,440)	(34,395)	(34,395)	(34,395)	(34,350)	(34,350)	(34,350)	(34,304)	(34,304)	(34,304)	(34,259)	(34,259)	(34,259)	
3.	Total Working Capital Balance	($34,440)	(34,395)	(34,395)	(34,395)	(34,350)	(34,350)	(34,350)	(34,304)	(34,304)	(34,304)	(34,259)	(34,259)	(34,259)	
4.	Average Net Working Capital Balance		(34,417)	(34,395)	(34,395)	(34,372)	(34,350)	(34,350)	(34,327)	(34,304)	(34,304)	(34,282)	(34,259)	(34,259)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		($166)	($166)	($166)	($166)	($166)	($166)	($166)	($166)	($166)	($166)	($166)	($166)	($1,992)
	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		(215)	(215)	(215)	(215)	(215)	(215)	(215)	(215)	(215)	(215)	(215)	(215)	(2,580)
7.	Expenses:														
	a. Gains		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		(33)	12	12	(33)	12	12	(33)	12	12	(33)	12	12	(36)
8.	Net Expenses (D)		(33)	12	12	(33)	12	12	(33)	12	12	(33)	12	12	(36)
9.	Total System Recoverable Expenses (Lines 6 + 8)		($248)	($203)	($203)	($248)	($203)	($203)	($248)	($203)	($203)	($248)	($203)	($203)	($2,616)
	a. Recoverable Costs Allocated to Energy		(248)	(203)	(203)	(248)	(203)	(203)	(248)	(203)	(203)	(248)	(203)	(203)	(2,616)
	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)		(248)	(203)	(203)	(248)	(203)	(203)	(248)	(203)	(203)	(248)	(203)	(203)	(2,616)
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)		($248)	($203)	($203)	($248)	($203)	($203)	($248)	($203)	($203)	($248)	($203)	($203)	($2,616)

Notes:
(A) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(B) Line 6 x 1.7144% x 1/12.
(C) Line 6 is reported on Schedule 7E.
(D) Line 8 is reported on Schedule 5E.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 to December 2019

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	(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)		$91,466	$91,215	$90,965	$90,714	$90,463	$90,212	$89,961	$89,710	$89,459	$89,208	$88,957	$88,706	$1,081,036
	b. Debt Component Grossed Up For Taxes (C)		27,015	26,941	26,867	26,792	26,718	26,644	26,570	26,496	26,422	26,348	26,274	26,199	319,286
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)		$170,360	$170,035	$169,711	$169,385	$169,060	$168,735	$168,410	$168,085	$167,760	$167,435	$167,110	$166,784	$2,022,870
	a. Recoverable Costs Allocated to Energy		170,360	170,035	169,711	169,385	169,060	168,735	168,410	168,085	167,760	167,435	167,110	166,784	2,022,870
	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)		170,360	170,035	169,711	169,385	169,060	168,735	168,410	168,085	167,760	167,435	167,110	166,784	2,022,870
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)		$170,360	$170,035	$169,711	$169,385	$169,060	$168,735	$168,410	$168,085	$167,760	$167,435	$167,110	$166,784	$2,022,870

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.40
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 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	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		$50,000	$250,000	$250,000	$0	$0	$0	$0	$0	$0	$50,000	$750,000	$750,000	$2,100,000
	b. Clearings to Plant (A)		(1,709,679)	0	0	0	0	0	0	0	0	0	0	0	(1,709,679)
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other - AFUDC (excl from CWIP)		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (B)	$2,378,414	668,735	668,735	668,735	668,735	668,735	668,735	668,735	668,735	668,735	668,735	668,735	668,735	
3.	Less: Accumulated Depreciation	($41,011)	(29,833)	(31,505)	(33,177)	(34,849)	(36,521)	(38,193)	(39,865)	(41,537)	(43,209)	(44,881)	(46,553)	(48,225)	
4.	CWIP - Non-Interest Bearing	$0	1,759,679	2,009,679	2,259,679	2,259,679	2,259,679	2,259,679	2,259,679	2,259,679	2,259,679	2,309,679	3,059,679	3,809,679	
5.	Net Investment (Lines 2 + 3 + 4)	$2,337,403	2,398,581	2,646,909	2,895,237	2,893,565	2,891,893	2,890,221	2,888,549	2,886,877	2,885,205	2,933,533	3,681,861	4,430,189	
6.	Average Net Investment		2,367,992	2,522,745	2,771,073	2,894,401	2,892,729	2,891,057	2,889,385	2,887,713	2,886,041	2,909,369	3,307,697	4,056,025	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		$11,454	$12,203	$13,404	$14,001	$13,993	$13,985	$13,976	$13,968	$13,960	$14,073	$16,000	$19,620	$170,637
	b. Debt Component Grossed Up For Taxes (D)		3,383	3,604	3,959	4,135	4,133	4,130	4,128	4,126	4,123	4,157	4,726	5,795	50,399
8.	Investment Expenses														
	a. Depreciation (E)		1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	$20,064
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		$16,509	$17,479	$19,035	$19,808	$19,798	$19,787	$19,776	$19,766	$19,755	$19,902	$22,398	$27,087	$241,100
	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		16,509	17,479	19,035	19,808	19,798	19,787	19,776	19,766	19,755	19,902	22,398	27,087	241,100
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (G)		16,509	17,479	19,035	19,808	19,798	19,787	19,776	19,766	19,755	19,902	22,398	27,087	241,100
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,509	$17,479	$19,035	$19,808	$19,798	$19,787	$19,776	$19,766	$19,755	$19,902	$22,398	$27,087	$241,100

Notes:

(A) $1,709,679 of expenditures included in Clearings to Plant CWIP for the 2018 Actual/Estimate projection will not be cleared to plant until after 2019. The adjustment is made in January 2019 amounts.
(B) Applicable depreciable base for Big Bend; accounts 312.44
(C) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(D) Line 6 x 1.7144% x 1/12.
(E) Applicable depreciation rate is 3.0%
(F) Line 9a x Line 10
(G) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: 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		$100,000	$65,000	$65,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$230,000
	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	115,595	215,595	280,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	
5.	Net Investment (Lines 2 + 3 + 4)	$115,595	215,595	280,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	
6.	Average Net Investment		165,595	248,095	313,095	345,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	345,595	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$801	$1,200	$1,514	$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$1,672	$18,563
	b. Debt Component Grossed Up For Taxes (C)		237	354	447	494	494	494	494	494	494	494	494	494	5,484
8.	Investment Expenses														
	a. Depreciation (D)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		$1,038	$1,554	$1,961	$2,166	$2,166	$2,166	$2,166	$2,166	$2,166	$2,166	$2,166	$2,166	$24,047
	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		1,038	1,554	1,961	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	24,047
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		1,038	1,554	1,961	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	24,047
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,038	$1,554	$1,961	$2,166	$2,166	$2,166	$2,166	$2,166	$2,166	$2,166	$2,166	$2,166	$24,047

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.44
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% 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 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend ELG Rule 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		$0	$0	$0	$0	$0	$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)	$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	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	
5.	Net Investment (Lines 2 + 3 + 4)	$150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	
6.	Average Net Investment		150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$726	$726	$726	$726	$726	$726	$726	$726	$726	$726	$726	$726	$8,712
	b. Debt Component Grossed Up For Taxes (C)		214	214	214	214	214	214	214	214	214	214	214	214	2,568
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)		$940	$940	$940	$940	$940	$940	$940	$940	$940	$940	$940	$940	$11,280
	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		940	940	940	940	940	940	940	940	940	940	940	940	11,280
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	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)		940	940	940	940	940	940	940	940	940	940	940	940	11,280
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$940	$940	$940	$940	$940	$940	$940	$940	$940	$940	$940	$940	$11,280

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.45
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% x 1/12.
(D) Applicable depreciation rate is 2.5%
(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 2019 to December 2019

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Section 316(b) Impingement Mortality
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$3,000,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	5,325,000	
	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	$5,325,000	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	2,475,000	2,725,000	2,975,000	3,225,000	3,475,000	3,725,000	3,975,000	4,225,000	4,475,000	4,725,000	4,975,000	5,225,000	150,000	
5.	Net Investment (Lines 2 + 3 + 4)	$2,475,000	2,725,000	2,975,000	3,225,000	3,475,000	3,725,000	3,975,000	4,225,000	4,475,000	4,725,000	4,975,000	5,225,000	5,475,000	
6.	Average Net Investment		2,600,000	2,850,000	3,100,000	3,350,000	3,600,000	3,850,000	4,100,000	4,350,000	4,600,000	4,850,000	5,100,000	5,350,000	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		$12,577	$13,786	$14,995	$16,205	$17,414	$18,623	$19,832	$21,042	$22,251	$23,460	$24,670	$25,879	$230,734
	b. Debt Component Grossed Up For Taxes (C)		3,715	4,072	4,429	4,786	5,143	5,500	5,858	6,215	6,572	6,929	7,286	7,643	68,148
8.	Investment Expenses														
	a. Depreciation (D)		-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	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)		$16,292	$17,858	$19,424	$20,991	$22,557	$24,123	$25,690	$27,257	$28,823	$30,389	$31,956	$33,522	$298,882
	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		16,292	17,858	19,424	20,991	22,557	24,123	25,690	27,257	28,823	30,389	31,956	33,522	298,882
10.	Energy Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		16,292	17,858	19,424	20,991	22,557	24,123	25,690	27,257	28,823	30,389	31,956	33,522	298,882
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,292	$17,858	$19,424	$20,991	$22,557	$24,123	$25,690	$27,257	$28,823	$30,389	$31,956	$33,522	$298,882

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,662,500) and 312.42 ($2,662,500)
(B) Line 6 x 5.8046% x 1/12. Based on ROE of 10.25% and weighted income tax rate of 25.345% (expansion factor of 1.34295)
(C) Line 6 x 1.7144% x 1/12.
(D) Applicable depreciation rate is 4.0% and 3.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
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 2018 through December 2018, is $960,463 compared to the original projection of $1,063,216. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M expense for the period January 2018 through December 2018 is $1,894,681 compared to the original projection of $4,423,789. The variance is due to greater operation on natural gas, compared to the original projection. This reduces the expected need for consumables and maintenance.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $932,808.

Estimated O&M costs for the period January 2019 through December 2019 are $709,500.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
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 2018 through December 2018 is $249,611 compared to the original projection of $280,951. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

There was no actual/estimated O&M expense projected, nor any original projection for the period January 2018 through December 2018.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $234,889.

There are no O&M costs projected for the period of January 2019 through December 2019.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
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 2018 through December 2018 is $51,105 compared to the original projection of $55,016. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $48,959.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
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 2018 through December 2018 is $80,406 compared to the original projection of $85,047. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $76,373

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
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 2018 through December 2018 is $58,125 compared to the original projection of $61,751. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $55,324.

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Project Title: Big Bend Units 1 & 2 FGD

Project Description:

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing SO_2 from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II is 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 2018 through December 2018 is $6,053,894 compared to the original projection of $6,674,906. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M expense for the period January 2018 through December 2018 is $570,804 compared to the original estimate of $2,200,000, resulting in a variance of -74.1 percent. This variance is due to Big Bend Units 1 and 2 burning more natural gas and less coal than projected, which reduced the consumables and maintenance needed.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $5,809,756.

Estimated O&M costs for the period January 2019 through December 2019 are $680,000.

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Project Title: Big Bend Section 114 Mercury Testing Platform

Project Description:

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance of emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform specialized mercury testing of the inlet and outlet of the last emission control device installed for Big Bend Units 1, 2 or 3, and Polk Unit 1 as part of the mercury data collection. Part of the cost incurred to perform the stack testing is due to the need to construct special test facilities at the Big Bend stack testing location to meet EPA's testing requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2018 through December 2018, is $8,562 compared to the original projection of $9,406. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $8,284.

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Project Title: Big Bend FGD Optimization and Utilization

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to optimize the SO_2 removal efficiency and operations of the Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric performed activities in three key areas to improve the performance and reliability of the Big Bend Units 1, 2 and 3 FGD systems. The majority of the improvements required on the Unit 3 tower module included the tower piping, nozzle and internal improvements, ductwork improvements, electrical system reliability improvements, tower control improvements, dibasic acid system improvements, booster fan reliability, absorber system improvements, quencher system improvements, and tower demister improvements. Big Bend Units 1 and 2 FGD system improvements included additional preventative maintenance, oxidation air control improvements, and tower water, air reagent and start-up piping upgrades. In order to ensure reliability of the FGD systems, improvements to the common limestone supply, gypsum de-watering stack reliability and wastewater treatment plant were also performed.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2018 through December 2018 is $1,554,567 compared to the original projection of $1,712,875. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $1,576,840.

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Project Title: Big Bend PM Minimization and Monitoring

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to develop a Best Operational Practices ("BOP") study to minimize emissions from each electrostatic precipitator ("ESP") at Big Bend, as well as perform a best available control technology ("BACT") analysis for the upgrade of each existing ESP. The company is also required to install and operate particulate matter continuous emission monitors on Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric identified improvements that were necessary to optimize ESP performance such as modifications to the turning vanes and precipitator distribution plates, and upgrades to the controls and software system of the precipitators. Tampa Electric incurred costs associated with the recommendations of the BOP study and the BACT analysis in 2001 and continues to make O&M and capital expenditures.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2018 through December 2018 is $1,809,209 compared to the original projection of $1,989,614. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M expense for the period January 2018 through December 2018 is $406,562 compared to the original projection of $611,283, resulting in a variance of -33.5 percent. This variance is due to less maintenance being required than expected, after inspection.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $1,751,406.

Estimated O&M costs for the period January 2019 through December 2019 are $398,500.

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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 2018 through December 2018 is $499,286 compared to the original projection of $562,354. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M expense for the period January 2018 through December 2018 is $78,693 compared to the original projection of $138,956, resulting in a variance of -43.4% percent. This variance is due to the operation of Big Bend Units 1 and 2 on natural gas.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $489,098.

Estimated O&M costs for the period January 2019 through December 2019 are $60,000.

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 2018 through December 2018 is $55,001 compared to the original projection of $35,856. The variance is due to the depreciation change requested in the 2018 actual-estimated filing submitted on July 25, 2018.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is projected to be $73,033.

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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 2018 through December 2018 is $90,462 compared to the original projection of $58,969. The variance is due to the depreciation change requested in the 2018 actual-estimated filing submitted on July 25, 2018.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $120,117.

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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 2018 through December 2018 is ($2,616) compared to the original projection of ($3,015). The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M for the period January 2018 through December 2018 is ($98) compared to the original projection of $9,151. 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: Estimated return on average net working capital for the period January 2019 through December 2019 is ($2,616).

There are no O&M costs projected for the period of January 2019 through December 2019.

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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 expense for the period January 2018 through December 2018 is $35,883 compared to the original projection of $34,500. The variance is not material.

Progress Summary: NPDES Surveillance fees are paid annually for the prior year.

Projections: Estimated O&M costs for the period January 2019 through December 2019 are $34,500.

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Project Title: Gannon Thermal Discharge Study

Project Description:

This project was a direct requirement from the FDEP in conjunction with the renewal of Tampa Electric's Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code, which constitute authorization for the company's Gannon Station facility to discharge to waters of the State under the NPDES. The FDEP permit is Permit No. FL0000809. Specifically, Tampa Electric was required to perform a 316(a) determination for Gannon Station to ensure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife with in 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 is no actual/estimated O&M expense projected, nor any original projection for the period January 2018 through December 2018.

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 no O&M costs projected for the period of January 2019 through December 2019.

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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 2018 through December 2018 is $113,289 compared to the original projection of $123,356. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M for the period January 2018 through December 2018 is $5,317 compared to the original projection of $19,988. The variance is not material.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $109,135.

Estimated O&M costs for the period January 2019 through December 2019 are $5,000.

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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 expense for the period January 2018 through December 2018 is $111,102, compared to the original projection of $203,882, resulting in a variance of -45.5 percent. This variance is due to the Bayside units' re-projected run time being less than originally projected, resulting in less ammonia consumption.

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: Estimated O&M costs for the period January 2019 through December 2019 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 2018 through December 2018 is $198,213 compared to the original projection of $218,523. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M expense for this project for the period January 2018 through December 2018 is $0, compared to the original projection of $37,200. The variance is not material.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $192,117.

There are no O&M costs projected for the period of January 2019 through December 2019.

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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 2019. 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 2018 through December 2018 is $137,625 compared to the original projection of $149,608. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M expense for this project for the period January 2018 through December 2018 is $39, compared to the original projection of $37,200. The variance is not material.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-1080-CO-EI, issued November 4, 2004. The project is complete and in service.

Projections: Estimated depreciation plus return for the period January 2019 through December 2019 is $132,473.

Estimated O&M costs for the period of January 2019 through December 2019 is are $6,000.

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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 2018 through 2019. 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 2018 through December 2018 is $130,774 compared to the original projection of $142,854. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M expense for this project for the period January 2018 through December 2018 is $1,450, compared to the original projection of $37,200. The variance is not material.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-1080-CO-EI, issued November 4, 2004. The project is complete and in service.

Projections: Estimated depreciation plus return for the period January 2019 through December 2019 is $126,179.

Estimated O&M costs for the period of January 2019 through December 2019 are $6,000.

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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 2018 through 2019. 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 2018 through December 2018 is $233,143 compared to the original projection of $256,173. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M for the period January 2018 through December 2018 is $3,808 compared to the original projection of $37,200. The variance is not material.

Progress Summary: This project was approved by the Commission in Docket No. 20040750-EI, Order No. PSC-2004-1080-CO-EI, issued November 4, 2004. The project is complete and in service.

Projections: Estimated depreciation plus return for the period January 2019 through December 2019 is $225,602.

Estimated O&M costs for the period of January 2019 through December 2019 is are $6,000.

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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 meeting 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 for the period January 2018 through December 2018 is $74,158 compared to the original projection of $321,000, resulting in a variance of -76.9 percent. The variance is related to uncertainty regarding the timing of the final requirements and reporting that must be submitted once the permit is finalized.

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. The project is complete and in service.

Projections: Estimated O&M costs for the period January 2019 through December 2019 are $90,000.

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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 from 2018 through 2019. 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 2018 through December 2018 is $7,960,376 compared to the original projection of $8,698,396. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M for the period January 2018 through December 2018 is $351,102 compared to the original projection of $1,498,585, resulting in a variance of -76.6 percent. This variance is due to greater use of natural gas and reduced use of coal, which reduced the unit's need for consumables and maintenance work, compared to the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0616-CO-EI, issued June 3, 2005. The project is complete and in service.

Projections: Estimated depreciation plus return for the period January 2019 through December 2019 is $7,567,577.

Estimated O&M costs for the period January 2019 through December 2019 are $167,240.

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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 from 2018 through 2019. 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 2018 through December 2018 is $8,407,010 compared to the original projection of $9,195,158. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M for the period January 2018 through December 2018 is $361,113 compared to the original projection of $1,629,977, resulting in a variance of -77.8 percent. This variance is due to operation of the unit on natural gas, which reduces the use of consumables and need for maintenance work, compared to the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0616-CO-EI, issued June 3, 2005. The project is complete and in service.

Projections: Estimated depreciation plus return for the period January 2019 through December 2019 is $8,288,466.

Estimated O&M costs for the period January 2019 through December 2019 are $261,200.

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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 from 2018 through 2019. 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 2018 through December 2018 is $6,968,871 compared to the original projection of $7,628,421. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M for the period January 2018 through December 2018 is $1,553,384 compared to the original projection of $1,694,774, resulting in a variance of -8.3 percent. This variance is due to greater use of natural gas, compared to the original projection.

Progress Summary: This project was approved by the Commission in Docket No. 20041376-EI, Order No. PSC-2005-0616-CO-EI, issued June 3, 2005. The project is complete and in service.

Projections: Estimated depreciation plus return for the period January 2019 through December 2019 is $6,730,895.

Estimated O&M costs for the period January 2019 through December 2019 are $396,460.

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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 from 2018 through 2019. 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 2018 through December 2018 is $5,420,387 compared to the original projection of $5,919,666. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M for the period January 2018 through December 2018 is $651,145 compared to the original projection of $1,061,162, resulting in a variance of -38.6 percent. This variance is due to less total run time estimated when compared to the original projection.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $5,379,650.

Estimated O&M costs for the period January 2019 through December 2019 are $2,135,100.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Arsenic Groundwater Standard Program

Project Description:
The Arsenic Groundwater Standard Program that is required by the Environmental Protection Agency and the Department of Environmental Protection became effective January 1, 2005. It requires regulated entities of the State of Florida to monitor the drinking water and groundwater Maximum Contaminant Level ("MCL") for arsenic under the federal rule known as the Safe Drinking Water Act.

Project Accomplishments:

Fiscal Expenditures: No O&M costs were included in the actual/estimated projection, nor were any included in the original projection for the period January 2018 through December 2018. The Big Bend Station Arsenic Plan of Study is complete and has been submitted to FDEP for its review; however, the scope of needed remediation activities is still under review.

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: There are no O&M costs projected for the period of January 2019 through December 2019.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Flue Gas Desulfurization ("FGD") System Reliability

Project Description:
The Big Bend FGD Reliability project is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems at Big Bend Station whenever coal is combusted in the units with few exceptions. The compliance dates for the strictest operational characteristics were January 1, 2011 for Big Bend Unit 3 and January 1, 2014 for Big Bend Units 1 and 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2018 through December 2018 is $2,080,400 compared to the original projection of $2,325,371. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $2,030,219.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Mercury Air Toxics Standards ("MATS")

Project Description:
In March 2005, the Environmental Protection Agency ("EPA") promulgated the Clean Air Mercury Rule ("CAMR") and was later challenged in court. On February 8, 2008, the Circuit Court of Appeals for the District of Columbia vacated CAMR and ordered a new rule by March 2011. On December 11, 2011, the EPA issued a final version of the rule that applies to all coal and oil-fired electric generating units with a capacity of 25 MW or more and with a compliance deadline is April 16, 2015. The rule sets forth hazardous air pollutant standards ("HAP") for mercury, non-mercury metal HAPs and acid gasses.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2018 through December 2018 is $824,496 compared to the original projection of $928,320. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M for the period January 2018 through December 2018 is $24,378 compared to the original projection of $231,000, resulting in a variance of -89.4 percent. Both Polk and Big Bend Power Stations achieved Low Emitting Electric Generating Unit status in 2017. As a result, monitoring is not required at this time, only periodic testing, and costs were lower 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: Estimated depreciation plus return for the period January 2019 through December 2019 is projected to be $802,679.

Estimated O&M costs for the period January 2019 through December 2019 are projected to be $74,878.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Greenhouse Gas Reduction Program

Project Description:
On September 22, 2009, the EPA enacted a new rule for reporting Greenhouse Gas ("GHG") emissions from large sources and suppliers effective January 1, 2010 in preparation for the first annual GHG report, due March 31, 2011. The new rule is intended to collect accurate and timely emissions data to inform future policy decisions as set forth in the final rule for GHG emission reporting pursuant to the Florida Climate Protection Act, Chapter 403.44 of the Florida Statutes and the docket EPA-HQ-OAR2008-0508-054. The nationwide GHG emissions reduction rule will impact Tampa Electric's generation fleet, components of its transmission and distribution system as well as company service vehicles. According to the rule, the company began collecting greenhouse gas emissions data effective January 1, 2010 to establish a baseline inventory to report to the EPA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2018 through December 2018 is $95,974 compared to the original projection of $93,149. The variance is not material.

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: Estimated O&M costs for the period January 2019 through December 2019 are $93,149.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Gypsum Storage Facility

Project Description:

The Big Bend New Gypsum Storage Facility is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems in order to comply with the CAAA. Gypsum is a by-product of the FGD operations and Tampa Electric had been managing its gypsum inventory through marketing efforts to sell gypsum an existing storage facility. However, the existing storage facility was no longer sufficient to hold the entire gypsum inventory, and Tampa Electric needed an additional storage facility. The new storage facility covers approximately 27 acres and holds approximately 870,000 tons of gypsum.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2018 through December 2018 is $2,073,526 compared to the original projection of $2,316,204. The variance is due to the TCJA tax rate change from 35 percent to 21 percent.

The actual/estimated O&M for the period January 2018 through December 2018 is $1,638,273 compared to the original projection of $1,663,000. The variance is not material.

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: Estimated depreciation plus return for the period January 2019 through December 2019 is $2,022,870.

Estimated O&M costs for the period January 2019 through December 2019 are $1,320,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
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 2018 through December 2018 for Phase I and Phase II is $130,502 and $2,299 compared to the original projections of $224,233 and $0 respectively. The variances are due to timing differences in the project schedules when compared to the original projections.

The actual/estimated O&M for the period January 2018 through December 2018 for Phase I and Phase II is $38,250 and $4,757,238, respectively, compared to the original projections of $0 and $6,125,000. The variances are due to timing differences in the project schedules when compared to the original projections. The projected expenditures are expected to be incurred in the future.

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 2019 through December 2019 for Phase I and Phase II is $241,100 and $24,047, respectively.

Estimated O&M costs for the period January 2019 through December 2019 for Phase II are $6,000,000. There are no O&M costs projected for Phase I.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Effluent Limitation Guidelines ("ELG") – Study and Compliance Program

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, 2019, and no later than December 31, 2023. Tampa Electric hired an engineering consulting firm to perform the Big Bend ELG Compliance Study, to be completed in 2018, concluding with a determination of the most appropriate ELG compliance measures identified through the study.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2018 through December 2018 for the Study program is $0, and for the proposed ELG Rule Compliance program it is $1,411. There were no original projections related to either of these ELG programs for the period.

The actual/estimated O&M for the period January 2018 through December 2018 for the Study program is $54,007, compared to $0 in the original projection. The variance is due to timing differences in the project schedule when compared to the original projection. There were no O&M costs included in the original projections for the proposed ELG Rule Compliance program.

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 company submitted its petition for approval of the proposed ELG Rule Compliance program to the Commission in this docket on May 9, 2018.

Projections: The ELG Rule Compliance program estimated depreciation plus return for the period January 2019 through December 2019 is $11,280.

The ELG Rule Compliance program projected O&M costs for the period of January 2019 through December 2019 are $0.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2019 through December 2019
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 Impingement Mortality-316(b)

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 2018 through December 2018 is $38,927. There was no original projection for this project for the period.

There are no actual/estimated O&M costs for the period January 2018 through December 2018, nor was there an original projection.

Progress Summary: The company submitted its petition for approval of this project to the Commission in this docket on April 26, 2018.

Projections: Estimated depreciation plus return for the period January 2019 through December 2019 is $298,882.

There are no O&M costs projected for the period of January 2019 through December 2019.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2019 to December 2019

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	53.88%	9,382,624	9,382,624	1,988	1.08036	1.05201	9,870,588	2,148	48.29%	57.05%	56.38%
GS, CS	65.19%	955,831	955,831	167	1.08036	1.05199	1,005,526	181	4.92%	4.81%	4.82%
GSD, SBF	75.74%	8,170,311	8,155,834	1,232	1.07581	1.04842	8,565,903	1,325	41.91%	35.19%	35.71%
IS	90.33%	800,071	785,633	101	1.02952	1.01769	814,225	104	3.98%	2.76%	2.85%
LS1	305.67%	173,595	173,595	6	1.05201	1.05201	182,623	7	0.89%	0.19%	0.24%
TOTAL *		19,482,432	19,453,517	3,494			20,438,865	3,765	100.00%	100.00%	100.00%

Notes:
(1) Average 12 CP load factor based on 2019 Projected calendar data
(2) Projected MWh sales for the period January 2019 to December 2019
(3) Effective sales at secondary level for the period January 2019 to December 2019.
(4) Column 2 / (Column 1 x 8760)
(5) Based on 2019 projected demand losses.
(6) Based on 2019 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

DOCKET NO. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-6P
EXHIBIT NO. PAR-4 , DOCUMENT NO. 6

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2019 to December 2019

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 25% Allocation Factor (%)	(3) Energy-Related Costs ($)	(4) Demand-Related Costs ($)	(5) Total Environmental Costs ($)	(6) Projected Sales at Meter (MWh)	(7) Effective Sales at Secondary Level (MWh)	**(8) Environmental Cost Recovery Factors (¢/kWh)**
RS	48.29%	56.38%	20378806	439,522	20,818,328	9,382,624	9,382,624	**0.222**
GS, CS	4.92%	4.82%	2,076,283	37,575	2,113,858	955,831	955,831	**0.221**
GSD, SBF	41.91%	35.71%	17,686,390	278,385	17,964,775	8,170,311	8,155,834	
Secondary								**0.220**
Primary								**0.218**
Transmission								**0.216**
IS	3.98%	2.85%	1,679,595	22,218	1,701,813	800,071	785,633	
Secondary								**0.217**
Primary								**0.214**
Transmission								**0.212**
LS1	0.89%	0.24%	375,588	1,871	377,459	173,595	173,595	**0.217**
TOTAL *	100.00%	100.00%	42,200,883	779,571	42,980,454	19,482,432	19,453,517	**0.221**

* Totals on this schedule may not foot due to rounding

Notes:
(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 11
(3) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(4) Column 2 x Total Demand Jurisdictional Dollars from Form 42-1P, line 5
(5) Column 3 + Column 4
(6) From Form 42-6P, Column 2
(7) From Form 42-6P, Column 3
(8) Column 5 / Column 7 x 10

DOCKET NO. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-7P
EXHIBIT NO. PAR-4, DOCUMENT NO. 7

Form 42 - 8P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2019 to December 2019

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 = 0.0289% * 46.00%	0.0133%
Equity = 0.0289% * 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	1.34295
Total Equity Component	5.8046%

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%
	7.5190%

Notes:

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

INDEX

ENVIRONMENTAL COST RECOVERY

COMMISSION FORMS

JANUARY 2019 THROUGH DECEMBER 2019

NOT INCLUDING THE COMPANY'S TWO

NEW PROPOSED ECRC PROJECTS

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3	Form 42-3P	86
4	Form 42-7P	87

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 30
PARTY: TAMPA ELECTRIC COMPANY (TECO)(DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-5

Tampa Electric Company Form 42 - 1P

Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered
Not Including the Company's Two New Proposed ECRC Projects
For the Projected Period
January 2019 to December 2019

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)	$12,438,028	$124,500	$12,562,528
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	44,588,995	458,297	45,047,292
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	57,027,023	582,797	57,609,820
2. True-up for Estimated Over/(Under) Recovery for the current period January 2018 to December 2018 (Form 42-2E, Line 5 + 6 + 10)	13,373,740	98,046	13,512,974
3. Final True-up for the period January 2017 to December 2017 (Form 42-1A, Line 3)	1,482,763	15,903	1,498,666
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2019 to December 2019 (Line 1 - Line 2- Line 3)	42,170,520	468,848	42,639,368
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$42,200,883	$469,186	$42,670,069

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 to December 2019
Not Including the Company's Two New Proposed ECRC Projects
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	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,125	$59,127	$709,500		$709,500
	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	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	d. Big Bend Units 1 & 2 FGD	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,667	56,663	680,000		680,000
	e. Big Bend PM Minimization and Monitoring	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,208	33,210	33,210	398,500		398,500
	f. Big Bend NO_x Emissions Reduction	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	60,000		60,000
	g. NPDES Annual Surveillance Fees	34,500	0	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	375	425	375	375	425	450	550	550	550	175	375	375	5,000		5,000
	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	500	500	500	500	500	500	500	500	500	500	500	500	6,000		6,000
	m. Big Bend Unit 2 Pre-SCR	500	500	500	500	500	500	500	500	500	500	500	500	6,000		6,000
	n. Big Bend Unit 3 Pre-SCR	500	500	500	500	500	500	500	500	500	500	500	500	6,000		6,000
	o. Clean Water Act Section 316(b) Phase II Study	5,000	15,000	0	20,000	0	25,000	25,000	0	0	0	0	0	90,000	90,000	
	p. Arsenic Groundwater Standard Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	q. Big Bend 1 SCR	0	0	10,000	22,320	0	0	0	31,140	0	93,780	10,000	0	167,240		167,240
	r. Big Bend 2 SCR	0	0	10,000	30,060	0	19,080	26,100	29,700	136,260	0	10,000	0	261,200		261,200
	s. Big Bend 3 SCR	11,700	37,960	25,000	24,660	0	30,780	16,020	21,060	43,740	111,220	59,200	15,120	396,460		396,460
	t. Big Bend 4 SCR	193,300	242,040	255,000	127,960	205,000	155,140	182,880	153,100	55,000	100,000	245,800	219,880	2,135,100		2,135,100
	u. Mercury Air Toxics Standards	0	0	7,823	55	0	6,250	10,500	9,750	10,500	9,750	10,500	9,750	74,878		74,878
	v. Greenhouse Gas Reduction Program	0	0	93,149	0	0	0	0	0	0	0	0	0	93,149		93,149
	w. Big Bend Gypsum Storage Facility (East 40)	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	110,000	1,320,000		1,320,000
	x. CCR Rule-Phase I	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	y. CCR Rule-Phase II	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	6,000,000		6,000,000
	z. Big Bend Unit 1 Section 316(b) Impingement Mortality	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	aa. Big Bend ELG Rule Compliance	0	0	0	0	0	0	0	0	0	0	0	0	0		0
2.	Total of O&M Activities	1,018,375	1,068,925	1,175,847	1,000,929	981,925	1,014,200	1,038,550	1,022,800	1,022,550	1,090,425	1,109,377	1,018,625	12,562,527	$124,500	$12,438,027
3.	Recoverable Costs Allocated to Energy	978,875	1,053,925	1,175,847	980,929	981,925	989,200	1,013,550	1,022,800	1,022,550	1,090,425	1,109,377	1,018,625	12,438,027		
4.	Recoverable Costs Allocated to Demand	39,500	15,000	0	20,000	0	25,000	25,000	0	0	0	0	0	124,500		
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)	978,875	1,053,925	1,175,847	980,929	981,925	989,200	1,013,550	1,022,800	1,022,550	1,090,425	1,109,377	1,018,625	12,438,028		
8.	Jurisdictional Demand Recoverable Costs (B)	39,500	15,000	0	20,000	0	25,000	25,000	0	0	0	0	0	124,500		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,018,375	$1,068,925	$1,175,847	$1,000,929	$981,925	$1,014,200	$1,038,550	$1,022,800	1,022,550	1,090,425	$1,109,377	$1,018,625	$12,562,528		

DOCKET NO. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-2P
EXHIBIT NO. PAR-5 , DOCUMENT NO. 2

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 to December 2019
Not Including the Company's Two New Proposed ECRC Projects
Capital Investment Projects-Recoverable Costs
(in Dollars)

Form 42-3P

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	$78,728	$78,547	$78,366	$78,186	$78,005	$77,825	$77,643	$77,463	$77,282	$77,102	$76,921	$76,740	$932,808		$932,808
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	2	20,131	20,030	19,929	19,827	19,725	19,624	19,523	19,422	19,321	19,220	19,119	19,018	234,889		234,889
	c.	Big Bend Unit 4 Continuous Emissions Monitors	3	4,160	4,145	4,130	4,116	4,102	4,087	4,073	4,059	4,043	4,029	4,015	4,000	48,959		48,959
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4	6,263	6,231	6,198	6,166	6,135	6,102	6,070	6,038	6,005	5,974	5,942	5,909	73,033	$73,033	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	5	10,300	10,247	10,194	10,142	10,089	10,036	9,983	9,931	9,878	9,825	9,772	9,720	120,117	120,117	
	f.	Big Bend Unit 1 Classifier Replacement	6	6,516	6,488	6,461	6,433	6,406	6,378	6,351	6,323	6,296	6,268	6,240	6,213	76,373		76,373
	g.	Big Bend Unit 2 Classifier Replacement	7	4,715	4,697	4,677	4,658	4,638	4,620	4,601	4,581	4,563	4,544	4,524	4,506	55,324		55,324
	h.	Big Bend Section 114 Mercury Testing Platform	8	700	699	696	695	693	691	690	687	686	684	682	681	8,284		8,284
	i.	Big Bend Units 1 & 2 FGD	9	493,173	491,532	489,890	488,249	486,608	484,967	483,326	481,685	480,043	478,402	476,761	475,120	5,809,756		5,809,756
	j.	Big Bend FGD Optimization and Utilization	10	133,093	132,750	132,450	132,151	131,850	131,550	131,249	130,950	130,649	130,349	130,050	129,749	1,576,840		1,576,840
	k.	Big Bend NO_x Emissions Reduction	11	41,109	41,046	40,981	40,918	40,854	40,790	40,726	40,662	40,599	40,535	40,471	40,407	489,098		489,098
	l.	Big Bend PM Minimization and Monitoring	12	148,048	147,667	147,286	146,904	146,523	146,141	145,760	145,378	144,997	144,615	144,234	143,853	1,751,406		1,751,406
	m.	Polk NO_x Emissions Reduction	13	9,247	9,219	9,192	9,164	9,136	9,108	9,081	9,053	9,025	8,998	8,970	8,942	109,135		109,135
	n.	Big Bend Unit 4 SOFA	14	16,230	16,190	16,150	16,110	16,069	16,029	15,989	15,950	15,910	15,870	15,830	15,790	192,117		192,117
	o.	Big Bend Unit 1 Pre-SCR	15	11,229	11,194	11,160	11,125	11,092	11,057	11,022	10,988	10,953	10,919	10,884	10,850	132,473		132,473
	p.	Big Bend Unit 2 Pre-SCR	16	10,683	10,653	10,622	10,591	10,561	10,530	10,500	10,469	10,438	10,408	10,377	10,347	126,179		126,179
	q.	Big Bend Unit 3 Pre-SCR	17	19,074	19,024	18,975	18,925	18,875	18,825	18,776	18,725	18,676	18,625	18,576	18,526	225,602		225,602
	r.	Big Bend Unit 1 SCR	18	641,285	639,349	637,412	635,474	633,538	631,600	629,663	627,725	625,789	623,851	621,914	619,977	7,567,577		7,567,577
	s.	Big Bend Unit 2 SCR	19	718,180	697,994	696,037	694,080	692,122	690,165	688,208	686,251	684,293	682,336	680,379	678,421	8,288,466		8,288,466
	t.	Big Bend Unit 3 SCR	20	569,595	568,016	566,436	564,856	563,277	561,698	560,118	558,539	556,960	555,379	553,800	552,221	6,730,895		6,730,895
	u.	Big Bend Unit 4 SCR	21	446,920	445,744	444,796	445,682	448,170	449,683	451,191	451,845	450,669	449,493	448,317	447,140	5,379,650		5,379,650
	v.	Big Bend FGD System Reliability	22	170,953	170,632	170,310	169,989	169,667	169,345	169,024	168,703	168,382	168,059	167,738	167,417	2,030,219		2,030,219
	w.	Mercury Air Toxics Standards	23	68,379	67,144	67,004	66,865	66,727	66,666	66,605	66,466	66,327	66,188	66,832	67,476	802,679		802,679
	x.	SO_2 Emissions Allowances (B)	24	(248)	(203)	(203)	(248)	(203)	(203)	(248)	(203)	(203)	(248)	(203)	(203)	(2,616)		(2,616)
	y.	Big Bend Gypsum Storage Facility	25	170,360	170,035	169,711	169,385	169,060	168,735	168,410	168,085	167,760	167,435	167,110	166,784	2,022,870		2,022,870
	z.	CCR-Phase I	26	16,509	17,479	19,035	19,808	19,798	19,787	19,776	19,766	19,755	19,902	22,398	27,087	241,100	241,100	
	aa.	CCR-Phase II	27	1,038	1,554	1,961	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	2,166	24,047	24,047	
	ab.	Big Bend ELG Rule Compliance	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	ac.	Big Bend Unit 1 Section 316(b) Impingement Mortali	29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
2.		Total Investment Projects - Recoverable Costs		3,816,370	3,788,103	3,779,856	3,772,417	3,765,683	3,758,002	3,750,276	3,741,707	3,731,262	3,720,928	3,713,819	3,708,857	45,047,280	$458,297	$44,588,983
3.		Recoverable Costs Allocated to Energy		3,782,260	3,752,592	3,742,468	3,734,135	3,727,495	3,719,911	3,712,281	3,703,806	3,693,458	3,683,061	3,673,541	3,663,975	44,588,983		44,588,983
4.		Recoverable Costs Allocated to Demand		34,110	35,511	37,388	38,282	38,188	38,091	37,995	37,901	37,804	37,867	40,278	44,882	458,297	458,297	
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)		3,782,260	3,752,592	3,742,468	3,734,135	3,727,495	3,719,911	3,712,281	3,703,806	3,693,458	3,683,061	3,673,541	3,663,975	44,588,995		
8.		Jurisdictional Demand Recoverable Costs (D)		34,110	35,511	37,388	38,282	38,188	38,091	37,995	37,901	37,804	37,867	40,278	44,882	458,297		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)		$3,816,370	$3,788,103	$3,779,856	$3,772,417	$3,765,683	$3,758,002	$3,750,276	$3,741,707	$3,731,262	$3,720,928	$3,713,819	$3,708,857	$45,047,292		

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. 20180007-EI
ECRC 2019 PROJECTION, FORM 42-3P
EXHIBIT NO. PAR-5 , DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
Not Including the Company's Two New Proposed ECRC Projects
January 2019 to December 2019

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 25% Allocation Factor (%)	(3) Energy-Related Costs ($)	(4) Demand-Related Costs ($)	(5) Total Environmental Costs ($)	(6) Projected Sales at Meter (MWh)	(7) Effective Sales at Secondary Level (MWh)	**(8) Environmental Cost Recovery Factors (¢/kWh)**
RS	48.29%	56.38%	20378806	264,527	20,643,333	9,382,624	9,382,624	**0.220**
GS, CS	4.92%	4.82%	2,076,283	22,615	2,098,898	955,831	955,831	**0.220**
GSD, SBF	41.91%	35.71%	17,686,390	167,546	17,853,936	8,170,311	8,155,834	
Secondary								**0.219**
Primary								**0.217**
Transmission								**0.215**
IS	3.98%	2.85%	1,679,595	13,372	1,692,967	800,071	785,633	
Secondary								**0.215**
Primary								**0.213**
Transmission								**0.211**
LS1	0.89%	0.24%	375,588	1,126	376,714	173,595	173,595	**0.217**
TOTAL *	100.00%	100.00%	42,200,883	469,186	42,670,069	19,482,432	19,453,517	**0.219**

* 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

Schedule 1A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period True-Up Amount
January 2017 - December 2017

Line No.		Period Amount ($)
1	End of Period Actual Total True-Up for the Period January 2017 - December 2017 (Schedule 2A, Line 5 + 6 + 9)	14,654,926
2	Estimated/Actual True-Up Amount approved for the period January 2017 - December 2017 (FPSC Order No. PSC-2018-0014-FOF-EI)	11,475,260
3	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2019 - December 2019 (Lines 1 - 2)	3,179,666

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 31
PARTY: GULF POWER COMPANY (GULF)
(DIRECT)
DESCRIPTION: C. Shane Boyett CSB-1

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)

January 2017 - December 2017
Calculation of the Current Period 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)	14,929,650	12,136,666	14,430,298	14,916,539	17,681,423	19,210,209	22,378,745	21,967,269	18,520,670	16,886,454	13,325,847	15,944,361	202,328,131
2	True-Up Provision (Order No. PSC-16-0535-FOF-EI)	908,460	908,465	908,465	908,465	908,465	908,465	908,465	908,465	908,465	908,465	908,465	908,465	10,901,575
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	15,838,110	13,045,131	15,338,763	15,825,004	18,589,888	20,118,674	23,287,210	22,875,734	19,429,135	17,794,919	14,234,312	16,852,826	213,229,706
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5A, Line 9)	2,714,366	2,996,924	3,908,479	3,074,115	303,190	2,340,942	3,852,354	3,382,882	5,135,820	2,246,992	3,502,190	3,327,819	36,786,074
	b Capital Investment Projects (Schedule 7A, Line 9)	13,402,083	13,370,324	13,395,498	13,784,123	13,771,381	13,759,589	13,425,015	13,396,176	13,388,669	13,379,573	13,411,434	13,379,631	161,863,495
	c **Total Jurisdictional ECRC Costs**	16,116,449	16,367,248	17,303,978	16,858,238	14,074,571	16,100,531	17,277,368	16,779,058	18,524,489	15,626,565	16,913,624	16,707,450	198,649,569
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	(278,339)	(3,322,117)	(1,965,215)	(1,033,234)	4,515,317	4,018,143	6,009,841	6,096,676	904,646	2,168,354	(2,679,313)	145,376	14,580,137
6	Interest Provision (Schedule 3A, Line 10)	4,284	2,496	521	(1,211)	(591)	2,177	6,127	10,744	10,769	11,743	13,866	13,865	74,790
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2016	4,578,165	3,395,650	(832,436)	(3,705,595)	(5,648,505)	(2,042,244)	1,069,611	6,177,114	11,376,069	11,383,019	12,654,651	9,080,740	4,578,165
	b Final True-Up from January 2015 - December 2015 (Order No. PSC-16-0535-FOF-EI)	3,061,120	3,061,120	3,061,120	3,061,120	3,061,120	3,061,120	3,061,120	3,061,120	3,061,120	3,061,120	3,061,120	3,061,120	3,061,120
8	True-Up Collected/(Refunded) (see Line 2)	(908,460)	(908,465)	(908,465)	(908,465)	(908,465)	(908,465)	(908,465)	(908,465)	(908,465)	(908,465)	(908,465)	(908,465)	(10,901,575)
9	Adjustments													0
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8 + 9)	6,456,770	2,228,684	(644,475)	(2,587,385)	1,018,876	4,130,731	9,238,234	14,437,189	14,444,139	15,715,771	12,141,860	11,392,636	11,392,636

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period True-Up Amount
January 2017 - December 2017

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 2E, Lines 7a + 7b)	7,639,285	6,456,770	2,228,684	(644,475)	(2,587,385)	1,018,876	4,130,731	9,238,234	14,437,189	14,444,139	15,715,771	12,141,860	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	6,452,486	2,226,188	(644,996)	(2,586,174)	1,019,467	4,128,554	9,232,107	14,426,445	14,433,371	15,704,028	12,127,993	11,378,771	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	14,091,771	8,682,957	1,583,688	(3,230,648)	(1,567,918)	5,147,430	13,362,839	23,664,680	28,870,560	30,148,168	27,843,765	23,520,630	
4	Average True-Up Amount (Line 3 x 1/2)	7,045,885	4,341,479	791,844	(1,615,324)	(783,959)	2,573,715	6,681,419	11,832,340	14,435,280	15,074,084	13,921,882	11,760,315	
5	Interest Rate (First Day of Reporting Business Month)	0.0074	0.0064	0.0094	0.0086	0.0095	0.0108	0.0112	0.0112	0.0106	0.0073	0.0114	0.0125	
6	Interest Rate (First Day of Subsequent Business Month)	0.0072	0.0074	0.0064	0.0094	0.0086	0.0095	0.0108	0.0106	0.0073	0.0114	0.0125	0.0158	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.0146	0.0138	0.0158	0.0180	0.0181	0.0203	0.0220	0.0218	0.0179	0.0187	0.0239	0.0283	
8	Average Interest Rate (Line 7 x 1/2)	0.00730	0.00690	0.00790	0.00900	0.00905	0.01015	0.01100	0.01090	0.00895	0.00935	0.01195	0.01415	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.000608	0.000575	0.000658	0.000750	0.000754	0.000846	0.000917	0.000908	0.000746	0.000779	0.000996	0.001179	
10	Interest Provision for the Month (Line 4 x Line 9)	4,284	2,496	521	(1,211)	(591)	2,177	6,127	10,744	10,769	11,743	13,866	13,865	74,790

Schedule 4A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2017 - December 2017

Variance Report of O & M Activities
(in Dollars)

Line		(1) Final Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent
1	Description of O & M Activities				
.1	Sulfur	0	0	0	0.0 %
.2	Air Emission Fees	227,149	253,397	(26,248)	(10.4) %
.3	Title V	242,047	192,312	49,735	25.9 %
.4	Asbestos Fees	0	0	0	0.0 %
.5	Emission Monitoring	716,594	798,292	(81,698)	(10.2) %
.6	General Water Quality	2,432,436	2,899,792	(467,356)	(16.1) %
.7	Groundwater Contamination Investigation	3,022,361	3,242,128	(219,767)	(6.8) %
.8	State NPDES Administration	65,231	67,729	(2,498)	(3.7) %
.9	Lead and Copper Rule	8,808	9,288	(480)	(5.2) %
.10	Env Auditing/Assessment	5,377	14,357	(8,980)	(62.5) %
.11	General Solid & Hazardous Waste	809,589	1,184,139	(374,550)	(31.6) %
.12	Above Ground Storage Tanks	42,029	63,065	(21,036)	(33.4) %
.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	41,523	(41,523)	(100.0) %
.17	Gulf Coast Ozone Study	0	0	0	0.0 %
.18	SPCC Substation Project	0	0	0	0.0 %
.19	FDEP NOx Reduction Agreement	1,212,726	1,232,057	(19,331)	(1.6) %
.20	Air Quality Compliance Program	23,833,315	23,172,689	660,626	2.9 %
.21	MACT ICR	0	0	0	0.0 %
.22	Crist Water Conservation	294,599	357,963	(63,364)	(17.7) %
.23	Coal Combustion Residual	4,880,645	6,103,183	(1,222,537)	(20.0) %
.24	Smith Water Conservation	167,586	224,136	(56,550)	(25.2) %
.25	Mercury Allowances	0	0	0	0.0 %
.26	Annual NOx Allowances	15,101	12,375	2,726	22.0 %
.27	Seasonal NOx Allowances	29,646	20,236	9,410	46.5 %
.28	SO2 Allowances	10,012	23,920	(13,908)	(58.1) %
.29	Scherer/Flint Credit - Energy	(202,437)	(228,418)	25,981	(11.4) %
.30	Scherer/Flint Credit - Demand	(9,178)	(11,308)	2,130	(18.8) %
2	Total O & M Activities	37,803,638	39,672,854	(1,869,216)	(4.7) %
3	Recoverable Costs Allocated to Energy	26,084,153	25,518,382	565,772	2.2 %
4	Recoverable Costs Allocated to Demand	11,719,485	14,154,472	(2,434,987)	(17.2) %

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

Schedule 5A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017

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	0
. 2	Air Emission Fees	1,695	1,786	112,081	1,861	1,800	1,673	2,900	90,340	2,331	3,498	3,244	3,939	227,149	0	227,149
. 3	Title V	(1,591)	12,700	20,820	17,299	12,107	34,066	20,560	26,175	22,933	18,071	28,312	30,593	242,047	0	242,047
. 4	Asbestos Fees	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 5	Emission Monitoring	68,775	57,533	70,428	68,847	67,675	50,535	60,869	55,956	56,802	49,806	61,041	48,327	716,594	0	716,594
. 6	General Water Quality	(33,307)	293,372	367,283	240,517	568,691	(146,930)	182,495	241,278	58,612	213,866	225,396	221,164	2,432,436	2,432,436	0
. 7	Groundwater Contamination Investigation	232,573	179,500	209,752	107,165	260,968	267,880	276,256	118,640	200,794	191,185	596,306	381,342	3,022,361	3,022,361	0
. 8	State NPDES Administration	27,231	38,000	0	0	0	0	0	0	0	0	0	0	65,231	65,231	0
. 9	Lead and Copper Rule	0	0	0	5,290	0	0	0	0	3,518	0	0	0	8,808	8,808	0
. 10	Env Auditing/Assessment	0	0	2,025	0	3,332	0	0	0	0	0	0	20	5,377	5,377	0
. 11	General Solid & Hazardous Waste	80,450	49,333	62,505	111,660	16,238	141,840	54,106	49,066	209,550	(110,159)	89,604	55,395	809,589	809,589	0
. 12	Above Ground Storage Tanks	1,901	1,033	1,298	1,125	23,782	(15,089)	1,593	493	662	358	17,589	7,284	42,029	42,029	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	69,592	57,040	106,806	108,165	133,247	263,015	98,547	105,199	176,517	172,864	(199,716)	121,449	1,212,726	0	1,212,726
. 20	Air Quality Compliance Program	2,201,486	2,082,821	2,908,942	2,207,889	(1,064,332)	1,560,301	2,462,443	1,753,379	4,202,183	1,554,828	1,644,270	2,319,105	23,833,315	0	23,833,315
. 21	MACT ICR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 22	Crist Water Conservation	7,678	2,277	24,430	10,947	6,733	17,261	100,015	39,866	31,615	4,211	22,455	27,109	294,599	294,599	0
. 23	Coal Combustion Residual	133,742	302,003	122,360	265,338	274,177	204,990	714,978	952,332	325,020	169,399	1,193,919	222,389	4,880,645	4,880,645	0
. 24	Smith Water Conservation	0	4,855	6,413	8,927	6,300	14,643	5,815	76,489	7,009	74,510	(49,684)	12,310	167,586	167,586	0
. 25	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 26	Annual NOx Allowances	1,110	633	1,199	454	384	620	963	974	876	3,006	2,695	2,186	15,101	0	15,101
. 27	Seasonal NOx Allowances	0	0	0	0	2,888	6,480	6,947	6,866	6,465	0	0	0	29,646	0	29,646
. 28	SO2 Allowances	736	(427)	938	2,291	202	457	908	1,217	1,022	952	898	817	10,012	0	10,012
. 29	Scherer/Flint Credit - Energy	0	0	0	0	0	0	(41,017)	(36,553)	(30,379)	(34,859)	(33,421)	(26,207)	(202,437)	0	(202,437)
. 30	Scherer/Flint Credit - Demand	0	0	0	0	0	0	(1,880)	(441)	(2,304)	(1,882)	1,323	(3,993)	(9,178)	(9,178)	0
2	Total of O & M Activities	2,792,072	3,082,459	4,017,279	3,157,777	314,192	2,401,742	3,946,498	3,481,277	5,273,228	2,309,653	3,604,231	3,423,229	37,803,638	11,719,485	26,084,153
3	Recoverable Costs Allocated to Energy	2,341,804	2,212,086	3,221,213	2,406,807	(846,027.89)	1,917,148	2,613,120	2,003,554	4,438,752	1,768,166	1,507,323	2,500,207	26,084,153		
4	Recoverable Costs Allocated to Demand	450,268	870,372	796,065	750,970	1,160,220	484,594	1,333,379	1,477,724	834,476	541,487	2,096,907	923,022	11,719,485		
5	Retail Energy Jurisdictional Factor	0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743			
6	Retail Demand Jurisdictional Factor	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277			
7	Jurisdictional Energy Recoverable Costs (A)	2,276,656	2,150,824	3,134,614	2,344,087	(824,675)	1,869,863	2,556,539	1,946,790	4,324,853	1,720,759	1,464,358	2,430,801	25,395,470		
8	Jurisdictional Demand Recoverable Costs (B)	437,711	846,100	773,865	730,028	1,127,865	471,079	1,295,814	1,436,093	810,967	526,232	2,037,833	897,018	11,390,604		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	2,714,366	2,996,924	3,908,479	3,074,115	303,190	2,340,942	3,852,354	3,382,882	5,135,820	2,246,992	3,502,190	3,327,819	36,786,074		

Notes:
(A) Line 3 x Line 5 x Line loss multiplier 1.0015 January - June; 1.0012 July - December
(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 2017 - December 2017

Variance Report of Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		(1) Final Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent	
1	Description of Investment Projects					
.1	Air Quality Assurance Testing	0	0	0	0.0	%
.2	Crist 5, 6 & 7 Precipitator Projects	4,252,540	4,252,540	0	0.0	%
.3	Crist 7 Flue Gas Conditioning	123,495	123,495	(0)	(0.0)	%
.4	Low NOx Burners, Crist 6 & 7	2,019,470	2,017,442	2,029	0.1	%
.5	CEMS - Plants Crist, & Daniel	676,890	675,533	1,357	0.2	%
.6	Substation Contamination Remediation	218,854	218,854	0	0.0	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	14,686	14,686	0	0.0	%
.8	Crist Cooling Tower Cell	43,331	43,331	0	0.0	%
.9	Crist Dechlorination System	26,505	26,505	0	0.0	%
.10	Crist Diesel Fuel Oil Remediation	4,240	4,240	0	0.0	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	5,478	5,478	0	0.0	%
.12	Crist IWW Sampling System	3,187	3,187	0	0.0	%
.13	Sodium Injection System	24,192	24,192	0	0.0	%
.14	Smith Stormwater Collection System	164,478	164,478	0	0.0	%
.15	Smith Waste Water Treatment Facility	25,031	27,485	(2,454)	(8.9)	%
.16	Daniel Ash Management Project	1,353,104	1,342,736	10,368	0.8	%
.17	Smith Water Conservation	1,967,125	1,948,177	18,948	1.0	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	11,839,273	11,842,958	(3,685)	(0.0)	%
.20	SPCC Compliance	85,471	85,471	0	0.0	%
.21	Crist Common FTIR Monitor	5,062	5,062	0	0.0	%
.22	Precipitator Upgrades for CAM Compliance	1,285,333	1,285,333	0	0.0	%
.23	Plant Groundwater Contamination	0	0	0	0.0	%
.24	Crist Water Conservation	1,955,628	1,953,505	2,123	0.1	%
.25	Plant NPDES Permit Compliance Projects	536,152	536,152	0	0.0	%
.26	Air Quality Compliance Program	139,944,126	139,872,775	71,351	0.1	%
.27	General Water Quality	38,537	43,612	(5,074)	(11.6)	%
.28	Coal Combustion Residual	(676,590)	(628,379)	(48,211)	(7.7)	%
.29	Effluent Limitations Guidelines	394,751	397,153	(2,402)	(0.6)	%
.30	Mercury Allowances	0	0	0	0.0	%
.31	Annual NOx Allowances	2,638	2,687	(50)	(1.9)	%
.32	Seasonal NOx Allowances	4,365	4,667	(302)	(6.5)	%
.33	SO2 Allowances	526,020	525,656	364	0.1	%
.34	Regulatory Asset Smith Units 1 & 2	1,773,516	1,773,516	0	0.0	%
.35	Scherer/Flint Credit - Energy	(163,613)	(163,441)	(172)	(0.1)	%
.36	Scherer/Flint Credit - Demand	(1,963,351)	(1,961,291)	(2,060)	(0.1)	%
2	Total Investment Projects - Recoverable Costs	166,509,924	166,467,793	42,132	0.0	%
3	Recoverable Costs Allocated to Energy	12,808,456	12,805,215	3,241	0.0	%
4	Recoverable Costs Allocated to Demand	153,701,469	153,662,578	38,891	0.0	%

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

Schedule 7A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017

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	0	0	0	0	0	0	0	0	0	0	0
. 2	Crist 5, 6 & 7 Precipitator Projects	343,594	342,862	342,141	353,702	352,942	352,183	352,936	363,814	363,125	362,436	361,747	361,059	4,252,540	3,925,422	327,118
. 3	Crist 7 Flue Gas Conditioning	9,850	9,849	9,847	10,354	10,352	10,351	10,325	10,513	10,513	10,513	10,513	10,513	123,495	113,995	9,500
. 4	Low NOx Burners, Crist 6 & 7	163,991	164,249	164,471	170,690	170,264	169,941	169,728	169,564	169,428	169,289	169,063	168,791	2,019,470	1,864,127	155,344
. 5	CEMS - Plants Crist & Daniel	59,163	59,075	58,989	61,266	61,444	61,798	56,688	51,401	51,570	51,475	52,226	51,796	676,890	624,822	52,068
. 6	Substation Contamination Remediation	17,882	17,852	17,822	18,493	18,461	18,430	18,398	18,366	18,335	18,303	18,272	18,240	218,854	202,019	16,835
. 7	Raw Water Well Flowmeters - Plants Crist & Smith	1,210	1,207	1,204	1,242	1,239	1,236	1,232	1,229	1,226	1,223	1,220	1,217	14,686	13,556	1,130
. 8	Crist Cooling Tower Cell	3,434	3,433	3,432	3,602	3,601	3,600	3,580	3,730	3,730	3,730	3,730	3,730	43,331	39,998	3,333
. 9	Crist Dechlorination System	2,208	2,201	2,193	2,243	2,235	2,227	2,219	2,211	2,204	2,196	2,188	2,180	26,505	24,466	2,039
. 10	Crist Diesel Fuel Oil Remediation	355	354	352	359	357	356	355	353	352	350	349	348	4,240	3,913	326
. 11	Crist Bulk Tanker Unload Sec Contain Struc	461	459	457	464	462	460	458	455	453	451	449	447	5,478	5,056	421
. 12	Crist IWW Sampling System	269	267	266	270	269	267	266	265	264	263	261	260	3,187	2,942	245
. 13	Sodium Injection System	2,002	1,996	1,991	2,046	2,040	2,034	2,028	2,023	2,017	2,011	2,005	1,999	24,192	22,331	1,861
. 14	Smith Stormwater Collection System	13,756	13,705	13,654	13,920	13,867	13,814	13,760	13,707	13,654	13,600	13,547	13,494	164,478	151,825	12,652
. 15	Smith Waste Water Treatment Facility	2,044	2,040	2,037	2,115	2,111	2,108	2,105	2,101	2,098	2,094	2,091	2,087	25,031	23,105	1,925
. 16	Daniel Ash Management Project	108,444	108,152	107,883	110,030	109,723	109,415	108,339	116,290	116,045	115,801	126,661	116,321	1,353,104	1,249,019	104,085
. 17	Smith Water Conservation	158,005	157,497	157,547	163,591	163,126	163,279	163,828	165,327	166,701	168,086	169,523	170,614	1,967,125	1,815,807	151,317
. 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	979,653	976,961	974,521	1,002,579	999,922	997,236	976,727	989,436	986,864	985,297	985,004	985,072	11,839,273	10,928,560	910,713
. 20	SPCC Compliance	7,068	7,049	7,030	7,228	7,208	7,188	7,167	7,147	7,127	7,107	7,087	7,066	85,471	78,896	6,575
. 21	Crist Common FTIR Monitor	420	418	417	428	427	426	424	423	422	420	419	418	5,062	4,673	389
. 22	Precipitator Upgrades for CAM Compliance	106,375	106,103	105,831	108,970	108,684	108,398	107,802	107,206	106,920	106,634	106,347	106,061	1,285,333	1,186,461	98,872
. 23	Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 24	Crist Water Conservation	160,739	160,359	160,028	164,989	164,717	164,438	164,031	163,660	163,232	162,822	163,139	163,474	1,955,628	1,805,196	150,433
. 25	Plant NPDES Permit Compliance Projects	44,327	44,208	44,088	45,340	45,214	45,088	44,962	44,837	44,711	44,585	44,459	44,333	536,152	494,910	41,242
. 26	Air Quality Compliance Program	11,378,748	11,348,385	11,374,091	11,690,186	11,676,998	11,662,729	11,760,851	11,831,514	11,815,037	11,800,647	11,819,984	11,784,957	139,944,126	129,179,193	10,764,933
. 27	General Water Quality	0	0	101	219	1,021	3,080	5,026	5,768	5,826	5,826	5,831	5,837	38,537	35,573	2,964
. 28	Coal Combustion Residual	16,241	16,710	18,671	19,606	20,656	21,930	(44,315)	(166,623)	(157,524)	(148,581)	(142,935)	(130,426)	(676,590)	(624,544)	(52,045)
. 29	Effluent Limitations Guidelines	21,237	23,284	24,631	28,848	31,428	34,025	36,861	38,766	38,778	38,903	38,982	39,007	394,751	364,385	30,365
. 30	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 31	Annual NOx Allowances	213	207	201	207	206	202	260	253	247	233	213	196	2,638	2,435	203
. 32	Seasonal NOx Allowances	436	436	436	459	448	416	369	323	277	256	256	256	4,365	4,030	336
. 33	SO2 Allowances	42,184	42,183	42,180	44,396	44,392	44,389	44,401	44,393	44,386	44,379	44,372	44,366	526,020	433,870	92,150
. 34	Regulatory Asset Smith Units 1 & 2	142,174	142,174	142,174	149,666	149,666	149,666	149,666	149,666	149,666	149,666	149,666	149,666	1,773,516	1,637,091	136,424
. 35	Scherer/Flint Credit - Energy	0	0	0	0	0	0	(27,185)	(27,187)	(27,202)	(27,236)	(27,392)	(27,411)	(163,613)	0	(163,613)
. 36	Scherer/Flint Credit - Demand	0	0	0	0	0	0	(326,225)	(326,242)	(326,427)	(326,830)	(328,699)	(328,927)	(1,963,351)	(1,963,351)	0
2	Total Investment Projects - Recoverable Costs	13,786,481	13,753,675	13,778,687	14,177,504	14,163,481	14,150,709	13,807,067	13,784,691	13,774,053.98	13,765,950	13,800,581	13,767,044	166,509,924	153,649,781	12,860,143
3	Recoverable Costs Allocated to Energy	1,060,499	1,057,975.00	1,059,899	1,090,577	1,089,499	1,088,516	1,062,082	1,060,361	1,059,543	1,058,919	1,061,583	1,059,003	12,808,456		
4	Recoverable Costs Allocated to Demand	12,725,983	12,695,700.00	12,718,789	13,086,927	13,073,982	13,062,193	12,744,985	12,724,330	12,714,511	12,707,031	12,738,998	12,708,041	153,701,469		
5	Retail Energy Jurisdictional Factor	0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743			
6	Retail Demand Jurisdictional Factor	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277			
7	Jurisdictional Energy Recoverable Costs (B)	1,030,996	1,028,675	1,031,405	1,062,158	1,062,000	1,061,668	1,039,085	1,030,319	1,032,355	1,030,528	1,031,323	1,029,605	12,470,117		
8	Jurisdictional Demand Recoverable Costs (C)	12,371,087	12,341,649	12,364,094	12,721,965	12,709,381	12,697,921	12,385,929	12,365,857	12,356,314	12,349,045	12,380,111	12,350,026	149,393,378		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	13,402,083	13,370,324	13,395,498	13,784,123	13,771,381	13,759,589	13,425,015	13,396,176	13,388,669	13,379,573	13,411,434	13,379,631	161,863,495		

Notes:
(A) Pages 1-29 of Schedule 8A, Line 9, Pages 30-33 of Schedule 8A, Line 6, Page 34 of Schedule 8A, Line 7, Exhibit CSB-3, Line 11 - Line 10 x 24%.
(B) Line 3 x Line 5 x Line loss multiplier 1.0015 January - June; 1.0012 July - December
(C)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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		0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	0.9724604	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	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) PEs 1006 & 1244 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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(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		(1,584)	0	0	0	0	0	0	0	0	0	0	0	(1,584)
	b Clearings to Plant		(1,584)	0	0	0	0	0	0	0	0	0	0	0	(1,584)
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	33,678,907	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	
3	Less: Accumulated Depreciation (C)	1,695,554	1,587,224	1,478,898	1,370,572	1,262,247	1,153,921	1,045,595	4,246,462	4,148,226	4,049,989	3,951,752	3,853,515	3,755,279	
4	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)	35,374,461	35,264,547	35,156,221	35,047,895	34,939,570	34,831,244	34,722,918	37,923,785	37,825,549	37,727,312	37,629,075	37,530,838	37,432,602	
6	Average Net Investment		35,319,504	35,210,384	35,102,058	34,993,733	34,885,407	34,777,081	36,323,352	37,874,667	37,776,430	37,678,194	37,579,957	37,481,720	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		188,606	188,023	187,445	204,188	203,556	202,924	211,947	220,999	220,425	219,852	219,279	218,706	2,485,952
	b Debt Component (Line 6 x Debt Component x 1/12)		46,657	46,513	46,370	41,188	41,060	40,933	42,753	44,578	44,463	44,347	44,232	44,116	527,209
8	Investment Expenses														
	a Depreciation (E)		98,241	98,237	98,237	98,237	98,237	98,237	98,237	98,237	98,237	98,237	98,237	98,237	1,178,846
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,089	10,089	10,089	10,089	10,089	10,089	0	0	0	0	0	0	60,534
	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)		343,594	342,862	342,141	353,702	352,942	352,183	352,936	363,814	363,125	362,436	361,747	361,059	4,252,540
	a Recoverable Costs Allocated to Energy		26,430	26,374	26,319	27,208	27,149	27,091	27,149	27,986	27,933	27,880	27,827	27,774	327,118
	b Recoverable Costs Allocated to Demand		317,163	316,488	315,822	326,494	325,793	325,092	325,787	335,828	335,192	334,557	333,921	333,285	3,925,422
10	Energy Jurisdictional Factor		0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	0.9724604	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		25,698	25,665	25,633	26,521	26,480	26,512	26,380	27,268	27,184	27,085	27,054	27,041	318,521
13	Retail Demand-Related Recoverable Costs (I)		308,318	307,662	307,015	317,389	316,707	316,026	316,609	326,367	325,749	325,131	324,513	323,895	3,815,382
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		334,017	333,327	332,647	343,910	343,187	342,538	342,989	353,635	352,933	352,216	351,568	350,937	4,133,903

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	1,446,934	1,446,721	1,446,508	1,446,295	1,446,082	1,445,869	1,445,656	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)	1,446,934	1,446,721	1,446,508	1,446,295	1,446,082	1,445,869	1,445,656	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	1,499,322	
6	Average Net Investment		1,446,828	1,446,615	1,446,402	1,446,189	1,445,976	1,445,763	1,472,489	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)		7,726	7,725	7,724	8,439	8,437	8,436	8,592	8,749	8,749	8,749	8,749	8,749	100,821
	b Debt Component (Line 6 x Debt Component x 1/12)		1,911	1,911	1,911	1,702	1,702	1,702	1,733	1,765	1,765	1,765	1,765	1,765	21,395
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		213	213	213	213	213	213	0	0	0	0	0	0	1,278
	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)		9,850	9,849	9,847	10,354	10,352	10,351	10,325	10,513	10,513	10,513	10,513	10,513	123,495
	a Recoverable Costs Allocated to Energy		758	758	757	796	796	796	794	809	809	809	809	809	9,500
	b Recoverable Costs Allocated to Demand		9,093	9,091	9,090	9,557	9,556	9,554	9,531	9,705	9,705	9,705	9,705	9,705	113,995
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		737	737	737	776	776	777	777	786	788	787	786	786	9,249
13	Retail Demand-Related Recoverable Costs (I)		8,839	8,838	8,836	9,291	9,289	9,288	9,262	9,431	9,431	9,431	9,431	9,431	110,799
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		9,576	9,574	9,574	10,066	10,066	10,065	10,039	10,217	10,219	10,218	10,217	10,217	120,048

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(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		44,083	75,019	7,260	(17,142)	(8,390)	4,803	11,744	13,342	18,255	8,707	1,400	1,488	160,568
	b Clearings to Plant		44,083	75,019	7,260	(17,142)	(8,390)	4,803	11,744	13,342	18,255	8,707	1,400	1,488	160,568
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		971	0	0	0	0	0	0	0	0	0	0	0	971
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,418,633	13,462,716	13,537,736	13,544,996	13,527,854	13,519,463	13,524,266	13,536,010	13,549,352	13,567,606	13,576,313	13,577,713	13,579,202	
3	Less: Accumulated Depreciation (C)	5,128,291	5,088,827	5,048,264	5,007,483	4,966,680	4,925,927	4,885,199	4,844,456	4,803,680	4,762,864	4,721,996	4,681,101	4,640,203	
4	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)	18,546,924	18,551,544	18,586,000	18,552,479	18,494,534	18,445,390	18,409,465	18,380,466	18,353,032	18,330,471	18,298,309	18,258,815	18,219,405	
6	Average Net Investment		18,549,234	18,568,772	18,569,239	18,523,506	18,469,962	18,427,428	18,394,966	18,366,749	18,341,751	18,314,390	18,278,562	18,239,110	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		99,053	99,157	99,160	108,085	107,772	107,524	107,335	107,170	107,024	106,864	106,655	106,425	1,262,225
	b Debt Component (Line 6 x Debt Component x 1/12)		24,504	24,529	24,530	21,802	21,739	21,689	21,651	21,618	21,588	21,556	21,514	21,467	268,187
8	Investment Expenses														
	a Depreciation (E)		38,723	38,851	39,070	39,091	39,041	39,017	39,031	39,065	39,104	39,157	39,183	39,187	468,521
	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)		163,991	164,249	164,471	170,690	170,264	169,941	169,728	169,564	169,428	169,289	169,063	168,791	2,019,470
	a Recoverable Costs Allocated to Energy		12,615	12,635	12,652	13,130	13,097	13,072	13,056	13,043	13,033	13,022	13,005	12,984	155,344
	b Recoverable Costs Allocated to Demand		151,376	151,615	151,820	157,560	157,167	156,869	156,672	156,521	156,395	156,267	156,059	155,807	1,864,127
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		12,264	12,285	12,312	12,788	12,767	12,750	12,773	12,674	12,698	12,673	12,634	12,623	151,241
13	Retail Demand-Related Recoverable Costs (I)		147,155	147,387	147,586	153,166	152,784	152,494	152,258	152,111	151,989	151,865	151,662	151,418	1,811,874
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		159,418	159,671	159,897	165,954	165,551	165,244	165,031	164,785	164,687	164,538	164,296	164,041	1,963,114

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) 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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist & Daniel
P.E.s 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311,1312, 1316, 1323, 1324, 1325, 1357, 1358, 1364, 1558, 1570, 1592, 1658, 1829, 1830
(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	77,100	50,469	(135)	(32)	(204)	(92)	82,379	(37,701)	171,783
	b Clearings to Plant		0	0	0	0	0	0	0	127,402	(204)	(92)	134	0	127,240
	c Retirements		0	0	0	0	0	0	0	36,972	0	0	0	0	36,972
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	2,038	2	2,040
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	4,629,584	4,629,584	4,629,584	4,629,584	4,629,584	4,629,584	4,629,584	4,629,584	4,720,015	4,719,810	4,719,718	4,719,852	4,719,852	
3	Less: Accumulated Depreciation (C)	2,155,573	2,142,410	2,129,247	2,116,084	2,102,920	2,089,757	2,076,594	581,827	605,635	592,208	578,782	567,394	553,970	
4	CWIP - Non Interest Bearing	0	0	0	0	0	77,100	127,569	127,434	0	0	0	82,244	44,543	
5	Net Investment (Lines 2 + 3 + 4) (A)	6,785,157	6,771,994	6,758,830	6,745,667	6,732,504	6,796,441	6,833,747	5,338,845	5,325,650	5,312,018	5,298,500	5,369,490	5,318,365	
6	Average Net Investment		6,778,575	6,765,412	6,752,249	6,739,086	6,764,472	6,815,094	6,086,296	5,332,247	5,318,834	5,305,259	5,333,995	5,343,928	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		36,198	36,127	36,057	39,323	39,471	39,766	35,514	31,114	31,035	30,956	31,124	31,182	417,866
	b Debt Component (Line 6 x Debt Component x 1/12)		8,954	8,937	8,920	7,932	7,962	8,021	7,164	6,276	6,260	6,244	6,278	6,290	89,238
8	Investment Expenses														
	a Depreciation (E)		13,163	13,163	13,163	13,163	13,163	13,163	13,163	13,163	13,427	13,426	13,426	13,427	159,012
	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		847	847	849	848	848	848	848	848	848	848	1,398	898	10,774
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		59,163	59,075	58,989	61,266	61,444	61,798	56,688	51,401	51,570	51,475	52,226	51,796	676,890
	a Recoverable Costs Allocated to Energy		4,551	4,544	4,538	4,713	4,726	4,754	4,361	3,954	3,967	3,960	4,017	3,984	52,068
	b Recoverable Costs Allocated to Demand		54,612	54,531	54,451	56,553	56,717	57,045	52,328	47,447	47,604	47,515	48,209	47,812	624,822
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		4,424	4,418	4,416	4,590	4,607	4,636	4,266	3,842	3,865	3,853	3,903	3,874	50,695
13	Retail Demand-Related Recoverable Costs (I)		53,089	53,010	52,932	54,976	55,135	55,454	50,853	46,110	46,262	46,176	46,851	46,465	607,314
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		57,513	57,428	57,348	59,566	59,743	60,090	55,120	49,952	50,128	50,030	50,754	50,338	658,009

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist $4,045,211; Daniel $584,373. Ending Balances: Crist $4,135,480; Daniel $584,373.
(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 1283, 1364 and 1658 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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Substation Contamination Remediation
P.E.s 1007, 2859, 3400, 3412, 3463, 3477
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	2,483,333	
3	Less: Accumulated Depreciation (C)	(471,458)	(475,953)	(480,449)	(484,945)	(489,440)	(493,936)	(498,432)	(502,927)	(507,423)	(511,919)	(516,414)	(520,910)	(525,405)	
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)	2,011,876	2,007,380	2,002,884	1,998,389	1,993,893	1,989,397	1,984,902	1,980,406	1,975,911	1,971,415	1,966,919	1,962,424	1,957,928	
6	Average Net Investment		2,009,628	2,005,132	2,000,637	1,996,141	1,991,645	1,987,150	1,982,654	1,978,158	1,973,663	1,969,167	1,964,671	1,960,176	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,731	10,707	10,683	11,647	11,621	11,595	11,569	11,543	11,516	11,490	11,464	11,438	136,005
	b Debt Component (Line 6 x Debt Component x 1/12)		2,655	2,649	2,643	2,349	2,344	2,339	2,334	2,328	2,323	2,318	2,312	2,307	28,901
8	Investment Expenses														
	a Depreciation (E)		4,496	4,496	4,496	4,496	4,496	4,496	4,496	4,496	4,496	4,496	4,496	4,496	53,948
	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)		17,882	17,852	17,822	18,493	18,461	18,430	18,398	18,366	18,335	18,303	18,272	18,240	218,854
	a Recoverable Costs Allocated to Energy		1,376	1,373	1,371	1,423	1,420	1,418	1,415	1,413	1,410	1,408	1,406	1,403	16,835
	b Recoverable Costs Allocated to Demand		16,506	16,479	16,451	17,070	17,041	17,012	16,983	16,954	16,925	16,895	16,866	16,837	202,019
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		1,337	1,335	1,334	1,385	1,384	1,383	1,385	1,373	1,374	1,370	1,365	1,364	16,390
13	Retail Demand-Related Recoverable Costs (I)		16,046	16,019	15,992	16,594	16,566	16,537	16,504	16,476	16,448	16,419	16,391	16,363	196,356
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		17,383	17,354	17,326	17,979	17,950	17,920	17,889	17,849	17,822	17,790	17,757	17,727	212,747

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist
P.E.s 1155 & 1606
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(33,724)	(34,162)	(34,599)	(35,037)	(35,474)	(35,911)	(36,349)	(36,786)	(37,224)	(37,661)	(38,098)	(38,536)	(38,973)	
4	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)	116,225	115,788	115,350	114,913	114,476	114,038	113,601	113,163	112,726	112,289	111,851	111,414	110,976	
6	Average Net Investment		116,006	115,569	115,132	114,694	114,257	113,819	113,382	112,945	112,507	112,070	111,632	111,195	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		619	617	615	669	667	664	662	659	656	654	651	649	7,783
	b Debt Component (Line 6 x Debt Component x 1/12)		153	153	152	135	134	134	133	133	132	132	131	131	1,654
8	Investment Expenses														
	a Depreciation (E)		437	437	437	437	437	437	437	437	437	437	437	437	5,249
	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)		1,210	1,207	1,204	1,242	1,239	1,236	1,232	1,229	1,226	1,223	1,220	1,217	14,686
	a Recoverable Costs Allocated to Energy		93	93	93	96	95	95	95	95	94	94	94	94	1,130
	b Recoverable Costs Allocated to Demand		1,117	1,114	1,112	1,146	1,143	1,140	1,138	1,135	1,132	1,129	1,126	1,123	13,556
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		90	90	90	93	93	93	93	92	92	92	91	91	1,100
13	Retail Demand-Related Recoverable Costs (I)		1,086	1,083	1,081	1,114	1,111	1,109	1,106	1,103	1,100	1,097	1,095	1,092	13,176
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,176	1,174	1,171	1,207	1,204	1,201	1,198	1,195	1,192	1,189	1,186	1,183	14,276

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	490,227	490,058	489,889	489,720	489,551	489,382	489,213	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)	490,227	490,058	489,889	489,720	489,551	489,382	489,213	531,926	531,926	531,926	531,926	531,926	531,926	
6	Average Net Investment		490,143	489,974	489,805	489,636	489,467	489,298	510,570	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)		2,617	2,616	2,616	2,857	2,856	2,855	2,979	3,104	3,104	3,104	3,104	3,104	34,916
	b Debt Component (Line 6 x Debt Component x 1/12)		647	647	647	576	576	576	601	626	626	626	626	626	7,401
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		169	169	169	169	169	169	0	0	0	0	0	0	1,014
	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)		3,434	3,433	3,432	3,602	3,601	3,600	3,580	3,730	3,730	3,730	3,730	3,730	43,331
	a Recoverable Costs Allocated to Energy		264	264	264	277	277	277	275	287	287	287	287	287	3,333
	b Recoverable Costs Allocated to Demand		3,170	3,169	3,168	3,325	3,324	3,323	3,305	3,443	3,443	3,443	3,443	3,443	39,998
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		257	257	257	270	270	270	269	279	280	279	279	279	3,245
13	Retail Demand-Related Recoverable Costs (I)		3,081	3,080	3,079	3,232	3,231	3,230	3,212	3,346	3,346	3,346	3,346	3,346	38,877
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,338	3,337	3,336	3,502	3,501	3,500	3,481	3,625	3,626	3,625	3,625	3,625	42,122

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Dechlorination System
P.E.s 1180 & 1248
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(215,366)	(216,477)	(217,587)	(218,698)	(219,808)	(220,919)	(222,029)	(223,140)	(224,250)	(225,361)	(226,471)	(227,582)	(228,692)	
4	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)	165,331	164,220	163,110	161,999	160,889	159,778	158,668	157,557	156,447	155,336	154,226	153,115	152,005	
6	Average Net Investment		164,775	163,665	162,554	161,444	160,333	159,223	158,112	157,002	155,891	154,781	153,670	152,560	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		880	874	868	942	936	929	923	916	910	903	897	890	10,867
	b Debt Component (Line 6 x Debt Component x 1/12)		218	216	215	190	189	187	186	185	183	182	181	180	2,312
8	Investment Expenses														
	a Depreciation (E)		1,111	1,111	1,111	1,111	1,111	1,111	1,111	1,111	1,111	1,111	1,111	1,111	13,326
	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)		2,208	2,201	2,193	2,243	2,235	2,227	2,219	2,211	2,204	2,196	2,188	2,180	26,505
	a Recoverable Costs Allocated to Energy		170	169	169	173	172	171	171	170	170	169	168	168	2,039
	b Recoverable Costs Allocated to Demand		2,038	2,031	2,025	2,070	2,063	2,056	2,048	2,041	2,034	2,027	2,020	2,013	24,466
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		165	165	164	168	168	167	167	165	165	164	164	163	1,985
13	Retail Demand-Related Recoverable Costs (I)		1,981	1,975	1,968	2,012	2,005	1,998	1,991	1,984	1,977	1,970	1,963	1,956	23,780
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,147	2,139	2,132	2,180	2,173	2,165	2,158	2,149	2,142	2,134	2,126	2,119	25,765

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(45,718)	(45,919)	(46,120)	(46,321)	(46,522)	(46,723)	(46,924)	(47,126)	(47,327)	(47,528)	(47,729)	(47,930)	(48,131)	
4	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)	23,205	23,004	22,803	22,602	22,401	22,200	21,999	21,798	21,596	21,395	21,194	20,993	20,792	
6	Average Net Investment		23,104	22,903	22,702	22,501	22,300	22,099	21,898	21,697	21,496	21,295	21,094	20,893	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		123	122	121	131	130	129	128	127	125	124	123	122	1,506
	b Debt Component (Line 6 x Debt Component x 1/12)		31	30	30	26	26	26	26	26	25	25	25	25	321
8	Investment Expenses														
	a Depreciation (E)		201	201	201	201	201	201	201	201	201	201	201	201	2,413
	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)		355	354	352	359	357	356	355	353	352	350	349	348	4,240
	a Recoverable Costs Allocated to Energy		27	27	27	28	27	27	27	27	27	27	27	27	326
	b Recoverable Costs Allocated to Demand		328	326	325	331	330	329	327	326	325	323	322	321	3,913
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		27	26	26	27	27	27	27	26	26	26	26	26	318
13	Retail Demand-Related Recoverable Costs (I)		319	317	316	322	321	319	318	317	316	314	313	312	3,804
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		345	344	342	349	348	346	345	343	342	341	339	338	4,121

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(76,537)	(76,833)	(77,129)	(77,425)	(77,721)	(78,017)	(78,313)	(78,609)	(78,905)	(79,201)	(79,497)	(79,793)	(80,089)	
4	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)	24,958	24,662	24,366	24,070	23,774	23,478	23,182	22,886	22,590	22,294	21,998	21,702	21,406	
6	Average Net Investment		24,810	24,514	24,218	23,922	23,626	23,330	23,034	22,738	22,442	22,146	21,850	21,554	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		132	131	129	140	138	136	134	133	131	129	127	126	1,587
	b Debt Component (Line 6 x Debt Component x 1/12)		33	32	32	28	28	27	27	27	26	26	26	25	338
8	Investment Expenses														
	a Depreciation (E)		296	296	296	296	296	296	296	296	296	296	296	296	3,553
	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)		461	459	457	464	462	460	458	455	453	451	449	447	5,478
	a Recoverable Costs Allocated to Energy		35	35	35	36	36	35	35	35	35	35	35	34	421
	b Recoverable Costs Allocated to Demand		426	424	422	428	426	424	422	420	419	417	415	413	5,056
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		34	34	34	35	35	34	34	34	34	34	34	33	410
13	Retail Demand-Related Recoverable Costs (I)		414	412	410	416	414	412	410	409	407	405	403	401	4,914
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		448	447	445	451	449	447	445	443	441	439	437	435	5,325

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(45,219)	(45,393)	(45,566)	(45,740)	(45,914)	(46,088)	(46,261)	(46,435)	(46,609)	(46,782)	(46,956)	(47,130)	(47,303)	
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) (A)	14,324	14,150	13,976	13,803	13,629	13,455	13,282	13,108	12,934	12,760	12,587	12,413	12,239	
6	Average Net Investment		14,237	14,063	13,889	13,716	13,542	13,368	13,195	13,021	12,847	12,674	12,500	12,326	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		76	75	74	80	79	78	77	76	75	74	73	72	909
	b Debt Component (Line 6 x Debt Component x 1/12)		19	19	18	16	16	16	16	15	15	15	15	15	194
8	Investment Expenses														
	a Depreciation (E)		174	174	174	174	174	174	174	174	174	174	174	174	2,084
	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)		269	267	266	270	269	267	266	265	264	263	261	260	3,187
	a Recoverable Costs Allocated to Energy		21	21	20	21	21	21	20	20	20	20	20	20	245
	b Recoverable Costs Allocated to Demand		248	247	246	249	248	247	246	245	243	242	241	240	2,942
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		20	20	20	20	20	20	20	20	20	20	20	19	239
13	Retail Demand-Related Recoverable Costs (I)		241	240	239	242	241	240	239	238	237	236	234	233	2,859
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		261	260	259	262	261	260	259	258	256	255	254	253	3,098

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(108,347)	(109,177)	(110,007)	(110,837)	(111,668)	(112,498)	(113,328)	(114,158)	(114,989)	(115,819)	(116,649)	(117,479)	(118,310)	
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) (A)	176,275	175,445	174,615	173,784	172,954	172,124	171,294	170,463	169,633	168,803	167,973	167,142	166,312	
6	Average Net Investment		175,860	175,030	174,199	173,369	172,539	171,709	170,879	170,048	169,218	168,388	167,558	166,727	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		939	935	930	1,012	1,007	1,002	997	992	987	983	978	973	11,734
	b Debt Component (Line 6 x Debt Component x 1/12)		232	231	230	204	203	202	201	200	199	198	197	196	2,495
8	Investment Expenses														
	a Depreciation (E)		830	830	830	830	830	830	830	830	830	830	830	830	9,963
	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)		2,002	1,996	1,991	2,046	2,040	2,034	2,028	2,023	2,017	2,011	2,005	1,999	24,192
	a Recoverable Costs Allocated to Energy		154	154	153	157	157	156	156	156	155	155	154	154	1,861
	b Recoverable Costs Allocated to Demand		1,848	1,843	1,837	1,889	1,883	1,878	1,872	1,867	1,862	1,856	1,851	1,846	22,331
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		150	149	149	153	153	153	153	151	151	151	150	150	1,812
13	Retail Demand-Related Recoverable Costs (I)		1,796	1,791	1,786	1,836	1,831	1,825	1,820	1,814	1,809	1,804	1,799	1,794	21,705
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,946	1,940	1,935	1,989	1,984	1,978	1,972	1,966	1,960	1,955	1,949	1,943	23,517

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(1,836,733)	(1,844,335)	(1,851,937)	(1,859,539)	(1,867,141)	(1,874,743)	(1,882,345)	(1,889,947)	(1,897,549)	(1,905,151)	(1,912,753)	(1,920,355)	(1,927,957)	
4	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)	927,646	920,044	912,442	904,840	897,238	889,636	882,034	874,432	866,830	859,228	851,626	844,024	836,422	
6	Average Net Investment		923,845	916,243	908,641	901,039	893,437	885,835	878,233	870,631	863,029	855,427	847,825	840,223	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,933	4,893	4,852	5,258	5,213	5,169	5,124	5,080	5,036	4,991	4,947	4,903	60,399
	b Debt Component (Line 6 x Debt Component x 1/12)		1,220	1,210	1,200	1,061	1,052	1,043	1,034	1,025	1,016	1,007	998	989	12,854
8	Investment Expenses														
	a Depreciation (E)		7,602	7,602	7,602	7,602	7,602	7,602	7,602	7,602	7,602	7,602	7,602	7,602	91,224
	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)		13,756	13,705	13,654	13,920	13,867	13,814	13,760	13,707	13,654	13,600	13,547	13,494	164,478
	a Recoverable Costs Allocated to Energy		1,058	1,054	1,050	1,071	1,067	1,063	1,058	1,054	1,050	1,046	1,042	1,038	12,652
	b Recoverable Costs Allocated to Demand		12,698	12,651	12,604	12,849	12,800	12,751	12,702	12,653	12,603	12,554	12,505	12,456	151,825
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		1,029	1,025	1,022	1,043	1,040	1,036	1,036	1,025	1,023	1,018	1,012	1,009	12,318
13	Retail Demand-Related Recoverable Costs (I)		12,344	12,298	12,253	12,491	12,443	12,395	12,344	12,296	12,248	12,200	12,153	12,105	147,570
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		13,372	13,323	13,275	13,534	13,483	13,432	13,379	13,321	13,272	13,219	13,165	13,114	159,888

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E.s 1466 & 1643
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	54,189	53,697	53,204	52,712	52,220	51,728	51,236	50,744	50,252	49,759	49,267	48,775	48,283	
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) (A)	233,151	232,658	232,166	231,674	231,182	230,690	230,198	229,706	229,213	228,721	228,229	227,737	227,245	
6	Average Net Investment		232,905	232,412	231,920	231,428	230,936	230,444	229,952	229,460	228,967	228,475	227,983	227,491	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,244	1,241	1,238	1,350	1,348	1,345	1,342	1,339	1,336	1,333	1,330	1,327	15,773
	b Debt Component (Line 6 x Debt Component x 1/12)		308	307	306	272	272	271	271	270	269	269	268	268	3,352
8	Investment Expenses														
	a Depreciation (E)		492	492	492	492	492	492	492	492	492	492	492	492	5,906
	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)		2,044	2,040	2,037	2,115	2,111	2,108	2,105	2,101	2,098	2,094	2,091	2,087	25,031
	a Recoverable Costs Allocated to Energy		157	157	157	163	162	162	162	162	161	161	161	161	1,925
	b Recoverable Costs Allocated to Demand		1,886	1,883	1,880	1,952	1,949	1,946	1,943	1,940	1,936	1,933	1,930	1,927	23,105
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		153	153	152	158	158	158	158	157	157	157	156	156	1,875
13	Retail Demand-Related Recoverable Costs (I)		1,834	1,831	1,828	1,898	1,895	1,892	1,888	1,885	1,882	1,879	1,876	1,872	22,458
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,987	1,983	1,980	2,056	2,053	2,050	2,046	2,042	2,039	2,035	2,032	2,029	24,332

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E.s 1501, 1535, 1555, & 1819
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	
3	Less: Accumulated Depreciation (C)	(7,801,285)	(7,845,160)	(7,889,035)	(7,932,909)	(7,976,784)	(8,020,658)	(8,064,533)	(5,761,792)	(5,796,670)	(5,831,549)	(5,866,428)	(5,901,306)	(5,936,185)	
4	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)	7,148,839	7,104,964	7,061,089	7,017,215	6,973,340	6,929,466	6,885,591	9,188,332	9,153,454	9,118,575	9,083,696	9,048,818	9,013,939	
6	Average Net Investment		7,126,901	7,083,027	7,039,152	6,995,277	6,951,403	6,907,528	8,036,962	9,170,893	9,136,014	9,101,136	9,066,257	9,031,378	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		38,058	37,823	37,589	40,817	40,561	40,305	46,896	53,512	53,309	53,105	52,902	52,698	547,576
	b Debt Component (Line 6 x Debt Component x 1/12)		9,415	9,357	9,299	8,233	8,182	8,130	9,460	10,794	10,753	10,712	10,671	10,630	115,635
8	Investment Expenses														
	a Depreciation (E)		34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	34,879	418,544
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		8,996	8,996	8,996	8,996	8,996	8,996	0	0	0	0	0	0	53,976
	d Property Taxes		17,097	17,097	17,121	17,105	17,105	17,105	17,105	17,105	17,105	17,105	28,210	18,114	217,374
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		108,444	108,152	107,883	110,030	109,723	109,415	108,339	116,290	116,045	115,801	126,661	116,321	1,353,104
	a Recoverable Costs Allocated to Energy		8,342	8,319	8,299	8,464	8,440	8,417	8,334	8,945	8,927	8,908	9,743	8,948	104,085
	b Recoverable Costs Allocated to Demand		100,102	99,832	99,585	101,567	101,283	100,999	100,005	107,344	107,119	106,893	116,918	107,373	1,249,019
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		8,110	8,089	8,076	8,243	8,227	8,209	8,153	8,692	8,698	8,669	9,465	8,699	101,330
13	Retail Demand-Related Recoverable Costs (I)		97,310	97,048	96,808	98,734	98,458	98,182	97,188	104,320	104,101	103,882	113,624	104,348	1,214,003
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		105,420	105,137	104,883	106,977	106,685	106,391	105,341	113,012	112,798	112,550	123,090	113,048	1,315,334

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1601
(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		(53,703)	21,236	61,648	(43,871)	23,161	87,610	123,459	334,740	157,682	316,159	121,812	273,153	1,423,085
	b Clearings to Plant		(53,703)	21,236	61,648	(43,871)	23,161	42,662	78,929	(25,803)	6,398	83,248	(525)	118,734	312,114
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	17,721,047	17,667,345	17,688,580	17,750,229	17,706,357	17,729,518	17,772,180	17,851,109	17,825,306	17,831,704	17,914,952	17,914,427	18,033,161	
3	Less: Accumulated Depreciation (C)	(159,367)	(200,710)	(241,928)	(283,195)	(324,607)	(365,916)	(407,279)	(448,741)	(490,388)	(531,974)	(573,576)	(615,371)	(657,165)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	44,947	89,477	450,020	601,305	834,216	956,553	1,110,972	
5	Net Investment (Lines 2 + 3 + 4) (A)	17,561,680	17,466,635	17,446,652	17,467,033	17,381,751	17,363,602	17,409,849	17,491,845	17,784,938	17,901,034	18,175,592	18,255,609	18,486,967	
6	Average Net Investment		17,514,157	17,456,644	17,456,843	17,424,392	17,372,676	17,386,726	17,450,847	17,638,392	17,842,986	18,038,313	18,215,601	18,371,288	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		93,526	93,218	93,220	101,671	101,370	101,452	101,826	102,920	104,114	105,254	106,288	107,196	1,212,054
	b Debt Component (Line 6 x Debt Component x 1/12)		23,136	23,060	23,060	20,509	20,448	20,464	20,540	20,760	21,001	21,231	21,440	21,623	257,272
8	Investment Expenses														
	a Depreciation (E)		41,343	41,218	41,267	41,411	41,309	41,363	41,463	41,647	41,586	41,601	41,796	41,794	497,799
	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)		158,005	157,497	157,547	163,591	163,126	163,279	163,828	165,327	166,701	168,086	169,523	170,614	1,967,125
	a Recoverable Costs Allocated to Energy		12,154	12,115	12,119	12,584	12,548	12,560	12,602	12,717	12,823	12,930	13,040	13,124	151,317
	b Recoverable Costs Allocated to Demand		145,851	145,381	145,428	151,007	150,578	150,719	151,226	152,610	153,878	155,156	156,483	157,490	1,815,807
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		11,816	11,780	11,793	12,256	12,231	12,250	12,329	12,357	12,494	12,583	12,669	12,760	147,318
13	Retail Demand-Related Recoverable Costs (I)		141,783	141,327	141,373	146,796	146,379	146,516	146,965	148,310	149,543	150,785	152,075	153,053	1,764,905
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		153,599	153,107	153,166	159,052	158,610	158,766	159,295	160,667	162,037	163,368	164,743	165,813	1,912,224

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.s 1272, 1404, 1628, 4418
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(317,931)	(320,812)	(323,693)	(326,574)	(329,455)	(332,337)	(335,218)	(338,099)	(340,980)	(343,861)	(346,743)	(349,624)	(352,505)	
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) (A)	629,994	627,113	624,232	621,351	618,469	615,588	612,707	609,826	606,945	604,063	601,182	598,301	595,420	
6	Average Net Investment		628,554	625,672	622,791	619,910	617,029	614,148	611,266	608,385	605,504	602,623	599,742	596,860	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,356	3,341	3,326	3,617	3,600	3,584	3,567	3,550	3,533	3,516	3,499	3,483	41,973
	b Debt Component (Line 6 x Debt Component x 1/12)		830	827	823	730	726	723	719	716	713	709	706	703	8,924
8	Investment Expenses														
	a Depreciation (E)		2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	32,689
	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)		7,068	7,049	7,030	7,228	7,208	7,188	7,167	7,147	7,127	7,107	7,087	7,066	85,471
	a Recoverable Costs Allocated to Energy		544	542	541	556	554	553	551	550	548	547	545	544	6,575
	b Recoverable Costs Allocated to Demand		6,524	6,507	6,489	6,672	6,653	6,635	6,616	6,597	6,579	6,560	6,541	6,523	78,896
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		529	527	526	542	540	539	539	534	534	532	530	528	6,401
13	Retail Demand-Related Recoverable Costs (I)		6,342	6,325	6,308	6,486	6,468	6,450	6,430	6,412	6,393	6,375	6,357	6,339	76,685
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,871	6,852	6,834	7,027	7,008	6,989	6,969	6,946	6,928	6,907	6,887	6,868	83,086

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; Panama City Beach $13,195.
(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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E.s 1031, 1158, 1167, 1199, 1250, 1258, 1287, 1958
(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		(50,763)	21,104	56	6,690	16,200	(2,200)	7,864	77,477	(205)	268,667	364,971	369,762	1,079,624
	b Clearings to Plant		(50,802)	2,914	139	561	241	1,281	50,281	9,729	(97)	(44)	63	63	14,329
	c Retirements		14,431	0	0	0	0	0	0	126,617	0	0	0	0	141,047
	d Cost of Removal		44,276	195	(167)	(609)	48,207	0	1,046	(0)	1,998	(2,001)	1	0	92,947
	e Salvage		9,111	(24,578)	0	0	47,533	0	0	0	0	0	0	0	32,066
2	Plant-in-Service/Depreciation Base (B)	120,146,872	120,081,640	120,084,553	120,084,692	120,085,253	120,085,494	120,086,775	120,137,056	120,020,169	120,020,072	120,020,028	120,020,092	120,020,154	
3	Less: Accumulated Depreciation (C)	(31,530,112)	(31,871,208)	(32,236,937)	(32,627,614)	(33,018,733)	(33,408,570)	(33,799,083)	(29,943,256)	(30,174,620)	(30,530,261)	(30,889,901)	(31,247,540)	(31,605,179)	
4	CWIP - Non Interest Bearing	5,663	5,702	23,892	23,809	29,938	45,898	42,418	0	67,748	67,639	336,350	701,258	1,070,958	
5	Net Investment (Lines 2 + 3 + 4) (A)	88,622,423	88,216,134	87,871,509	87,480,888	87,096,458	86,722,821	86,330,109	90,193,800	89,913,296	89,557,450	89,466,477	89,473,810	89,485,933	
6	Average Net Investment		88,419,279	88,043,821	87,676,198	87,288,673	86,909,640	86,526,465	88,261,955	90,053,548	89,735,373	89,511,963	89,470,144	89,479,872	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		472,159	470,154	468,191	509,329	507,118	504,882	515,009	525,462	523,606	522,302	522,058	522,115	6,062,385
	b Debt Component (Line 6 x Debt Component x 1/12)		116,802	116,306	115,820	102,739	102,293	101,842	103,884	105,993	105,619	105,356	105,306	105,318	1,287,277
8	Investment Expenses														
	a Depreciation (E)		348,017	347,827	347,835	347,836	347,837	347,838	347,829	347,976	347,635	347,635	347,634	347,635	4,173,533
	b Amortization (F)		10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	120,058
	c Dismantlement		32,670	32,670	32,670	32,670	32,670	32,670	0	0	0	0	0	0	196,020
	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)		979,653	976,961	974,521	1,002,579	999,922	997,236	976,727	989,436	986,864	985,297	985,004	985,072	11,839,273
	a Recoverable Costs Allocated to Energy		75,358	75,151	74,963	77,121	76,917	76,710	75,133	76,110	75,913	75,792	75,770	75,775	910,713
	b Recoverable Costs Allocated to Demand		904,295	901,811	899,558	925,457	923,005	920,526	901,594	913,326	910,951	909,505	909,234	909,297	10,928,560
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		73,261	73,070	72,948	75,112	74,976	74,818	73,506	73,954	73,965	73,760	73,610	73,671	886,651
13	Retail Demand-Related Recoverable Costs (I)		879,076	876,661	874,472	899,648	897,265	894,855	876,194	887,595	885,288	883,882	883,619	883,680	10,622,236
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		952,338	949,731	947,419	974,760	972,241	969,673	949,700	961,549	959,253	957,642	957,229	957,352	11,508,887

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) Portions of PEs 1158, 1167 and 1199 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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(27,324)	(27,507)	(27,691)	(27,874)	(28,058)	(28,241)	(28,424)	(28,608)	(28,791)	(28,975)	(29,158)	(29,341)	(29,525)	
4	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)	35,546	35,363	35,180	34,996	34,813	34,629	34,446	34,263	34,079	33,896	33,712	33,529	33,346	
6	Average Net Investment		35,455	35,271	35,088	34,904	34,721	34,538	34,354	34,171	33,987	33,804	33,621	33,437	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		189	188	187	204	203	202	200	199	198	197	196	195	2,360
	b Debt Component (Line 6 x Debt Component x 1/12)		47	47	46	41	41	41	40	40	40	40	40	39	502
8	Investment Expenses														
	a Depreciation (E)		183	183	183	183	183	183	183	183	183	183	183	183	2,201
	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)		420	418	417	428	427	426	424	423	422	420	419	418	5,062
	a Recoverable Costs Allocated to Energy		32	32	32	33	33	33	33	33	32	32	32	32	389
	b Recoverable Costs Allocated to Demand		387	386	385	395	394	393	392	390	389	388	387	386	4,673
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		31	31	31	32	32	32	32	32	32	31	31	31	379
13	Retail Demand-Related Recoverable Costs (I)		376	375	374	384	383	382	381	379	378	377	376	375	4,542
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		408	407	406	416	415	414	413	411	410	409	407	406	4,921

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1175, 1191, 1305, 1330
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	
3	Less: Accumulated Depreciation (C)	(4,137,304)	(4,178,136)	(4,218,967)	(4,259,798)	(4,300,629)	(4,341,461)	(4,382,292)	(4,511,346)	(4,552,177)	(4,593,009)	(4,633,840)	(4,674,671)	(4,715,502)	
4	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)	9,860,392	9,819,560	9,778,729	9,737,898	9,697,066	9,656,235	9,615,404	9,486,350	9,445,519	9,404,687	9,363,856	9,323,025	9,282,193	
6	Average Net Investment		9,839,976	9,799,145	9,758,313	9,717,482	9,676,651	9,635,819	9,550,877	9,465,934	9,425,103	9,384,272	9,343,440	9,302,609	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		52,545	52,327	52,109	56,702	56,463	56,225	55,729	55,234	54,995	54,757	54,519	54,281	655,888
	b Debt Component (Line 6 x Debt Component x 1/12)		12,999	12,945	12,891	11,437	11,389	11,341	11,241	11,141	11,093	11,045	10,997	10,949	139,470
8	Investment Expenses														
	a Depreciation (E)		40,831	40,831	40,831	40,831	40,831	40,831	40,831	40,831	40,831	40,831	40,831	40,831	489,975
	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)		106,375	106,103	105,831	108,970	108,684	108,398	107,802	107,206	106,920	106,634	106,347	106,061	1,285,333
	a Recoverable Costs Allocated to Energy		8,183	8,162	8,141	8,382	8,360	8,338	8,292	8,247	8,225	8,203	8,181	8,159	98,872
	b Recoverable Costs Allocated to Demand		98,193	97,942	97,691	100,588	100,324	100,059	99,510	98,960	98,695	98,431	98,167	97,903	1,186,461
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		7,955	7,936	7,922	8,164	8,149	8,133	8,113	8,013	8,014	7,983	7,947	7,932	96,260
13	Retail Demand-Related Recoverable Costs (I)		95,454	95,210	94,966	97,783	97,526	97,269	96,706	96,172	95,915	95,658	95,401	95,144	1,153,205
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		103,409	103,146	102,888	105,947	105,675	105,402	104,819	104,185	103,929	103,641	103,349	103,077	1,249,466

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E.s 1218 & 1361
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project
P.E.s 1178, 1227 & 1298
(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		4,397	741	(137)	4,408	35,407	2,142	(45)	(11)	(68)	(2,021)	205,699	860	251,372
	b Clearings to Plant		0	47,984	(137)	(550)	(236)	29,578	13,121	(11)	(68)	(2,021)	3,263	(105)	90,818
	c Retirements		0	28,760	0	0	0	31,276	0	5,979	0	0	0	0	66,015
	d Cost of Removal		(2,617)	13	(11)	(42)	(17)	0	0	0	0	2,000	3,190	(131)	2,386
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	19,999,118	19,999,118	20,018,343	20,018,206	20,017,656	20,017,420	20,015,722	20,028,843	20,022,853	20,022,784	20,020,763	20,024,026	20,023,921	
3	Less: Accumulated Depreciation (C)	(4,640,416)	(4,701,370)	(4,730,935)	(4,789,340)	(4,847,774)	(4,906,183)	(4,933,298)	(4,991,684)	(5,044,129)	(5,102,535)	(5,158,942)	(5,214,152)	(5,272,693)	
4	CWIP - Non Interest Bearing	42,846	47,243	0	0	4,958	40,602	13,166	0	0	0	0	202,436	203,400	
5	Net Investment (Lines 2 + 3 + 4) (A)	15,401,549	15,344,991	15,287,408	15,228,866	15,174,840	15,151,839	15,095,590	15,037,159	14,978,724	14,920,249	14,861,821	15,012,310	14,954,629	
6	Average Net Investment		15,373,270	15,316,199	15,258,137	15,201,853	15,163,339	15,123,714	15,066,374	15,007,941	14,949,487	14,891,035	14,937,065	14,983,469	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		82,093	81,789	81,478	88,703	88,478	88,247	87,912	87,571	87,230	86,889	87,158	87,429	1,034,977
	b Debt Component (Line 6 x Debt Component x 1/12)		20,308	20,233	20,156	17,893	17,847	17,801	17,733	17,664	17,596	17,527	17,581	17,636	219,973
8	Investment Expenses														
	a Depreciation (E)		58,337	58,337	58,394	58,393	58,392	58,391	58,386	58,424	58,407	58,406	58,401	58,410	700,678
	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)		160,739	160,359	160,028	164,989	164,717	164,438	164,031	163,660	163,232	162,822	163,139	163,474	1,955,628
	a Recoverable Costs Allocated to Energy		12,365	12,335	12,310	12,691	12,671	12,649	12,618	12,589	12,556	12,525	12,549	12,575	150,433
	b Recoverable Costs Allocated to Demand		148,374	148,023	147,718	152,297	152,046	151,789	151,414	151,071	150,676	150,298	150,590	150,899	1,805,196
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		12,021	11,994	11,979	12,361	12,351	12,337	12,345	12,233	12,234	12,189	12,191	12,226	146,459
13	Retail Demand-Related Recoverable Costs (I)		144,236	143,895	143,599	148,050	147,806	147,556	147,148	146,815	146,431	146,063	146,348	146,648	1,754,595
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		156,257	155,889	155,578	160,411	160,157	159,893	159,492	159,047	158,665	158,252	158,539	158,874	1,901,055

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E.s 1204 & 1299
(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 Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	6,153,140	6,153,140	6,153,140	6,153,140	6,153,140	
3	Less: Accumulated Depreciation (C)	(2,183,984)	(2,201,933)	(2,219,882)	(2,237,831)	(2,255,779)	(2,273,728)	(2,291,677)	(2,309,625)	(2,327,574)	(2,345,523)	(2,363,472)	(2,381,420)	(2,399,369)	
4	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)	3,969,156	3,951,207	3,933,258	3,915,310	3,897,361	3,879,412	3,861,463	3,843,515	3,825,566	3,807,617	3,789,669	3,771,720	3,753,771	
6	Average Net Investment		3,960,181	3,942,233	3,924,284	3,906,335	3,888,386	3,870,438	3,852,489	3,834,540	3,816,592	3,798,643	3,780,694	3,762,746	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		21,147	21,052	20,956	22,793	22,689	22,584	22,479	22,375	22,270	22,165	22,060	21,956	264,525
	b Debt Component (Line 6 x Debt Component x 1/12)		5,231	5,208	5,184	4,598	4,577	4,556	4,534	4,513	4,492	4,471	4,450	4,429	56,242
8	Investment Expenses														
	a Depreciation (E)		17,949	17,949	17,949	17,949	17,949	17,949	17,949	17,949	17,949	17,949	17,949	17,949	215,385
	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)		44,327	44,208	44,088	45,340	45,214	45,088	44,962	44,837	44,711	44,585	44,459	44,333	536,152
	a Recoverable Costs Allocated to Energy		3,410	3,401	3,391	3,488	3,478	3,468	3,459	3,449	3,439	3,430	3,420	3,410	41,242
	b Recoverable Costs Allocated to Demand		40,918	40,807	40,697	41,852	41,736	41,620	41,504	41,388	41,271	41,155	41,039	40,923	494,910
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		3,315	3,306	3,300	3,397	3,390	3,383	3,384	3,351	3,351	3,338	3,322	3,316	40,153
13	Retail Demand-Related Recoverable Costs (I)		39,777	39,669	39,562	40,685	40,572	40,459	40,334	40,222	40,109	39,996	39,883	39,770	481,038
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		43,092	42,976	42,862	44,082	43,962	43,842	43,718	43,573	43,460	43,333	43,205	43,086	521,191

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Compliance Program

P.E.s 1034, 1035, 1036, 1037, 1067, 1095, 1168, 1188, 1222, 1233, 1279, 1288, 1362, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1684, 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 1809, 1810, 1824, 1826, 1909, 1911, 1913, 1950
(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		43,024	242,708	215,760	342,800	3,415,715	(37,818)	87,958	1,001,775	771,227	1,471,645	1,788,010	1,455,893	10,798,697
	b Clearings to Plant		41,576	315,080	100,994	(39,089)	112,196	524,478	126,018	94,110	10,727	534,147	2,167,021	504,768	4,492,026
	c Retirements		2,378,506	522,011	2,772	0	0	1,174,701	0	64,762	0	4,356	53,207	77,293	4,277,607
	d Cost of Removal		74,783	216,822	16,353	(8,252)	25,541	557	(234)	68,538	464,109	149,909	26,399	8,244	1,042,769
	e Salvage		(29,607)	224,580	0	0	57,472	59,986	0	0	4,329	5,865	114,596	0	437,221
2	Plant-in-Service/Depreciation Base (B)	1,299,352,112	1,297,015,181	1,296,808,250	1,296,906,472	1,296,867,383	1,296,979,579	1,296,329,356	1,340,343,171	1,340,372,519	1,340,383,247	1,340,913,038	1,343,026,852	1,343,454,328	
3	Less: Accumulated Depreciation (C)	(228,386,837)	(229,632,398)	(232,839,777)	(236,541,586)	(240,271,034)	(244,024,030)	(246,630,124)	(229,667,299)	(233,012,874)	(236,031,815)	(239,362,159)	(242,877,180)	(246,277,835)	
4	CWIP - Non Interest Bearing	608,419	609,867	537,495	652,261	1,034,149	4,337,668	3,775,372	3,737,318	4,644,983	5,405,482	6,342,980	5,963,969	6,915,094	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,071,573,694	1,067,992,650	1,064,505,968	1,061,017,147	1,057,630,498	1,057,293,218	1,053,474,605	1,114,413,190	1,112,004,628	1,109,756,914	1,107,893,860	1,106,113,642	1,104,091,588	
6	Average Net Investment		1,069,783,172	1,066,249,309	1,062,761,557	1,059,323,823	1,057,461,858	1,055,383,911	1,103,175,244	1,113,208,909	1,110,880,771	1,108,825,387	1,107,003,751	1,105,102,615	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,712,642	5,693,771	5,675,147	6,181,155	6,170,290	6,158,165	6,437,028	6,495,574	6,481,989	6,469,996	6,459,367	6,448,274	74,383,397
	b Debt Component (Line 6 x Debt Component x 1/12)		1,413,184	1,408,515	1,403,908	1,246,824	1,244,633	1,242,187	1,298,437	1,310,247	1,307,507	1,305,087	1,302,943	1,300,706	15,784,178
8	Investment Expenses														
	a Depreciation (E)		3,388,251	3,381,427	3,380,728	3,380,990	3,380,859	3,381,160	3,453,198	3,453,506	3,453,353	3,453,376	3,454,663	3,460,823	41,022,335
	b Amortization (F)		25,309	25,309	25,309	25,309	25,309	25,309	25,368	25,368	25,368	25,368	25,368	25,368	304,061
	c Dismantlement		314,897	314,897	314,897	314,897	314,897	314,897	0	0	0	0	0	0	1,889,382
	d Property Taxes		524,465	524,465	574,102	541,011	541,011	541,011	546,819	546,819	546,819	546,819	577,643	549,786	6,560,773
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		11,378,748	11,348,385	11,374,091	11,690,186	11,676,998	11,662,729	11,760,851	11,831,514	11,815,037	11,800,647	11,819,984	11,784,957	139,944,126
	a Recoverable Costs Allocated to Energy		875,288	872,953	874,930	899,245	898,231	897,133	904,681	910,116	908,849	907,742	909,230	906,535	10,764,933
	b Recoverable Costs Allocated to Demand		10,503,460	10,475,432	10,499,161	10,790,941	10,778,768	10,765,596	10,856,170	10,921,398	10,906,188	10,892,905	10,910,755	10,878,421	129,179,193
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		850,938	848,777	851,408	875,812	875,560	875,006	885,092	884,331	885,528	883,404	883,312	881,369	10,480,538
13	Retail Demand-Related Recoverable Costs (I)		10,210,544	10,183,298	10,206,365	10,490,008	10,478,175	10,465,370	10,550,327	10,613,717	10,598,935	10,586,027	10,603,373	10,571,951	125,558,092
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		11,061,482	11,032,075	11,057,774	11,365,820	11,353,735	11,340,376	11,435,419	11,498,048	11,484,463	11,469,431	11,486,686	11,453,321	136,038,630

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $787,513,529; Smith $229,742; Daniel $372,027,931, Scherer $139,580,911. Ending Balances: Crist $787,385,496; Smith $229,742; Daniel $372,892,410, Scherer $182,946,680.
(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 PE 1168, 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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E. 0831 & 1280
(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	30,470	1,539	227,236	360,100	194,899	16,753	(243)	330	969	870	832,922
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	30,470	32,008	259,245	619,345	814,244	830,996	830,753	831,083	832,052	832,922	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	0	30,470	32,008	259,245	619,345	814,244	830,996	830,753	831,083	832,052	832,922	
6	Average Net Investment		0	0	15,235	31,239	145,627	439,295	716,794	822,620	830,875	830,918	831,568	832,487	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	81	182	850	2,563	4,182	4,800	4,848	4,848	4,852	4,858	32,065
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	20	37	171	517	844	968	978	978	979	980	6,472
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	101	219	1,021	3,080	5,026	5,768	5,826	5,826	5,831	5,837	38,537
	a Recoverable Costs Allocated to Energy		0	0	8	17	79	237	387	444	448	448	449	449	2,964
	b Recoverable Costs Allocated to Demand		0	0	94	202	943	2,843	4,640	5,325	5,378	5,378	5,382	5,388	35,573
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		0	0	8	16	77	231	378	431	437	436	436	437	2,886
13	Retail Demand-Related Recoverable Costs (I)		0	0	91	197	916	2,764	4,509	5,174	5,226	5,227	5,231	5,237	34,572
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	99	213	993	2,995	4,887	5,606	5,663	5,663	5,667	5,673	37,458

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residual
P.E.s 0404, 0412, 0424, 0514, 1641, 1997, 4405, 4430, 6756, 6757, 6759, 6765, CCR-C, CCR-D, CCR-S
(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		51,513	94,878	142,568	138,059	167,361	200,713	240,856	1,021,588	1,689,309	976,893	675,882	2,996,801	8,396,420
	b Clearings to Plant		162	2,412	(3,237)	0	1,156	0	0	0	0	0	1,689	672,088	674,270
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	76,251	76,251
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	1,059,749	1,059,910	1,062,322	1,059,086	1,059,086	1,060,242	1,060,242	1,076,526	1,076,526	1,076,526	1,076,526	1,078,215	1,750,303	
3	Less: Accumulated Depreciation (C)	(24,301)	(27,189)	(30,078)	(32,975)	(35,861)	(38,748)	(41,638)	(36,131,692)	(36,189,470)	(36,247,247)	(36,305,025)	(36,362,803)	(36,344,332)	
4	CWIP - Non Interest Bearing	944,872	996,223	1,088,689	1,234,494	1,372,553	1,538,758	1,739,470	2,507,975	3,529,563	5,218,873	6,195,765	6,869,958	9,194,671	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,980,320	2,028,944	2,120,933	2,260,605	2,395,777	2,560,251	2,758,074	(32,547,191)	(31,583,381)	(29,951,849)	(29,032,734)	(28,414,630)	(25,399,358)	
6	Average Net Investment		2,004,632	2,074,939	2,190,769	2,328,191	2,478,014	2,659,163	(14,622,673)	(32,065,286)	(30,767,615)	(29,492,291)	(28,723,682)	(26,906,994)	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,705	11,080	11,699	13,585	14,459	15,516	(85,323)	(187,101)	(179,529)	(172,088)	(167,603)	(157,002)	(871,602)
	b Debt Component (Line 6 x Debt Component x 1/12)		2,648	2,741	2,894	2,740	2,917	3,130	(17,211)	(37,741)	(36,213)	(34,712)	(33,808)	(31,670)	(174,285)
8	Investment Expenses														
	a Depreciation (E)		2,889	2,889	2,896	2,887	2,887	2,890	2,917	2,917	2,917	2,917	2,917	2,920	34,842
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	54,861	54,861	54,861	54,861	54,861	54,861	329,164
	d Property Taxes		0	0	1,182	394	394	394	441	441	441	441	697	466	5,291
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		16,241	16,710	18,671	19,606	20,656	21,930	(44,315)	(166,623)	(157,524)	(148,581)	(142,935)	(130,426)	(676,590)
	a Recoverable Costs Allocated to Energy		1,249	1,285	1,436	1,508	1,589	1,687	(3,409)	(12,817)	(12,117)	(11,429)	(10,995)	(10,033)	(52,045)
	b Recoverable Costs Allocated to Demand		14,992	15,425	17,234	18,098	19,067	20,243	(40,907)	(153,806)	(145,407)	(137,152)	(131,940)	(120,393)	(624,544)
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		1,215	1,250	1,398	1,469	1,549	1,645	(3,335)	(12,454)	(11,806)	(11,123)	(10,682)	(9,754)	(50,629)
13	Retail Demand-Related Recoverable Costs (I)		14,574	14,995	16,754	17,593	18,536	19,679	(39,754)	(149,473)	(141,310)	(133,288)	(128,223)	(117,001)	(606,920)
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		15,789	16,244	18,151	19,062	20,085	21,324	(43,089)	(161,927)	(153,116)	(144,411)	(138,905)	(126,755)	(657,549)

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $441,895; Smith $461,621; Daniel $104,724; Scherer $51,509; Scholz $0. Ending Balances: Crist $441,896; Smith $462,055; Daniel $104,724; Scherer $69,540; Scholz $672,088.
(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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Capital Investments, Depreciation and Taxes
For Project: Effluent Limitations Guidelines
P.E.s 0830, 1193, 1912
(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		782,340	(167,630)	571,830	260,787	475,247	265,366	543,732	(395)	3,596	32,249	(9,834)	16,977	2,774,265
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	2,797,110	3,579,450	3,411,820	3,983,650	4,244,437	4,719,684	4,985,050	5,528,782	5,528,387	5,531,983	5,564,232	5,554,398	5,571,375	
5	Net Investment (Lines 2 + 3 + 4) (A)	2,797,110	3,579,450	3,411,820	3,983,650	4,244,437	4,719,684	4,985,050	5,528,782	5,528,387	5,531,983	5,564,232	5,554,398	5,571,375	
6	Average Net Investment		3,188,280	3,495,635	3,697,735	4,114,044	4,482,061	4,852,367	5,256,916	5,528,584	5,530,185	5,548,107	5,559,315	5,562,886	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		17,025	18,667	19,746	24,005	26,153	28,314	30,674	32,259	32,269	32,373	32,439	32,459	326,383
	b Debt Component (Line 6 x Debt Component x 1/12)		4,212	4,618	4,885	4,842	5,275	5,711	6,187	6,507	6,509	6,530	6,543	6,548	68,368
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)		21,237	23,284	24,631	28,848	31,428	34,025	36,861	38,766	38,778	38,903	38,982	39,007	394,751
	a Recoverable Costs Allocated to Energy		1,634	1,791	1,895	2,219	2,418	2,617	2,835	2,982	2,983	2,993	2,999	3,001	30,365
	b Recoverable Costs Allocated to Demand		19,604	21,493	22,736	26,629	29,011	31,408	34,026	35,784	35,795	35,911	35,983	36,006	364,385
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (H)		1,588	1,742	1,844	2,161	2,357	2,553	2,774	2,898	2,906	2,912	2,913	2,917	29,565
13	Retail Demand-Related Recoverable Costs (I)		19,057	20,894	22,102	25,886	28,202	30,532	33,067	34,776	34,786	34,899	34,970	34,992	354,163
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		20,645	22,635	23,946	28,047	30,558	33,084	35,842	37,674	37,693	37,811	37,883	37,909	383,727

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 1.0015 Januanry - June; 1.0012 July - December
(I) Line 9b x Line 11.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
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		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	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 1.0015 Januanry - June; 1.0012 July - December
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 7A.
(E) Line 8 is reported on Schedule 5A.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
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	32,585	31,475	30,733	29,534	29,534	29,149	28,530	36,576	35,602	34,726	31,720	29,024	26,839	
	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	32,585	31,475	30,733	29,534	29,534	29,149	28,530	36,576	35,602	34,726	31,720	29,024	26,839	
4	Average Net Working Capital Balance		32,030	31,104	30,133	29,534	29,342	28,840	37,058	36,089	35,164	33,223	30,372	27,931	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		171	166	161	172	171	168	216	211	205	194	177	163	2,176
	b Debt Component (Line 4 x Debt Component x 1/12)		42	41	40	35	35	34	44	42	41	39	36	33	462
6	Total Return Component (D)		213	207	201	207	206	202	260	253	247	233	213	196	2,638
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		1,110	633	1,199	454	384	620	963	974	876	3,006	2,695	2,186	15,101
8	Net Expenses (E)		1,110	633	1,199	454	384	620	963	974	876	3,006	2,695	2,186	15,101
9	Total System Recoverable Expenses (Lines 6 + 8)		1,323	841	1,399	662	590	822	1,223	1,227	1,123	3,239	2,908	2,382	17,739
	a Recoverable Costs Allocated to Energy		1,126	649	1,214	470	400	635	983	993	895	3,024	2,712	2,201	15,304
	b Recoverable Costs Allocated to Demand		197	191	185	191	190	187	240	234	228	215	197	181	2,435
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		1,095	631	1,181	458	390	620	962	965	872	2,943	2,634	2,140	14,892
13	Retail Demand-Related Recoverable Costs (C)		191	186	180	186	185	181	233	227	221	209	191	176	2,366
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,287	817	1,362	644	575	801	1,195	1,192	1,094	3,152	2,825	2,315	17,259

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 1.0015 Januanry - June; 1.0012 July - December
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 7A.
(E) Line 8 is reported on Schedule 5A.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
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	65,398	65,398	65,398	65,398	65,398	62,510	56,030	49,320	42,693	36,443	36,443	36,443	36,443	
	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	65,398	65,398	65,398	65,398	65,398	62,510	56,030	49,320	42,693	36,443	36,443	36,443	36,443	
4	Average Net Working Capital Balance		65,398	65,398	65,398	65,398	63,954	59,270	52,675	46,006	39,568	36,443	36,443	36,443	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		349	349	349	382	373	346	307	268	231	213	213	213	3,593
	b Debt Component (Line 4 x Debt Component x 1/12)		86	86	86	77	75	70	62	54	47	43	43	43	773
6	Total Return Component (D)		436	436	436	459	448	416	369	323	277	256	256	256	4,365
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	2,888	6,480	6,947	6,866	6,465	0	0	0	29,646
8	Net Expenses (E)		0	0	0	0	2,888	6,480	6,947	6,866	6,465	0	0	0	29,646
9	Total System Recoverable Expenses (Lines 6 + 8)		436	436	436	459	3,336	6,896	7,316	7,188	6,743	256	256	256	34,011
	a Recoverable Costs Allocated to Energy		34	34	34	35	2,922	6,512	6,975	6,890	6,487	20	20	20	29,982
	b Recoverable Costs Allocated to Demand		402	402	402	423	414	384	341	298	256	236	236	236	4,030
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		33	33	33	34	2,848	6,352	6,824	6,695	6,320	19	19	19	29,229
13	Retail Demand-Related Recoverable Costs (C)		391	391	391	411	402	373	331	289	249	229	229	229	3,917
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		423	423	423	446	3,251	6,725	7,155	6,985	6,569	248	248	248	33,146

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 1.0015 Januanry - June; 1.0012 July - December
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 7A.
(E) Line 8 is reported on Schedule 5A.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
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	50	10	0	0	10	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	6,335,546	6,334,656	6,334,687	6,333,596	6,332,426	6,332,174	6,331,556	6,332,860	6,331,482	6,330,298	6,329,185	6,328,125	6,327,147	
	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	(2,123.41)	(1,970.09)	(1,816.77)	(1,663.45)	(1,510.13)	(1,460.48)	(1,349.74)	(1,198.17)	(1,036.69)	(875.21)	(723.46)	(561.98)	(400.51)	
3	Total Working Capital Balance	6,333,422	6,332,686	6,332,870	6,331,932	6,330,916	6,330,714	6,330,207	6,331,662	6,330,445	6,329,423	6,328,461	6,327,563	6,326,746	
4	Average Net Working Capital Balance		6,333,054	6,332,778	6,332,401	6,331,424	6,330,815	6,330,460	6,332,121	6,331,054	6,329,934	6,328,942	6,328,012	6,327,155	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		33,819	33,817	33,815	36,944	36,940	36,938	36,948	36,942	36,935	36,929	36,924	36,919	433,870
	b Debt Component (Line 4 x Debt Component x 1/12)		8,366	8,366	8,365	7,452	7,451	7,451	7,453	7,452	7,450	7,449	7,448	7,447	92,150
6	Total Return Component (D)		42,184	42,183	42,180	44,396	44,392	44,389	44,401	44,393	44,386	44,379	44,372	44,366	526,020
7	Expenses														
	a Gains		(153.32)	(153.32)	(153.32)	(153.32)	(49.65)	(160.41)	(161.48)	(161.48)	(161.48)	(161.48)	(161.48)	(161.47)	(1,792.21)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		890	(274)	1,091	2,444	252	618	1,070	1,379	1,183	1,113	1,060	978	11,804
8	Net Expenses (E)		736	(427)	938	2,291	202	457	908	1,217	1,022	952	898	817	10,012
9	Total System Recoverable Expenses (Lines 6 + 8)		42,921	41,755	43,118	46,687	44,594	44,847	45,309	45,611	45,407	45,330	45,270	45,183	536,032
	a Recoverable Costs Allocated to Energy		3,981	2,817	4,183	5,706	3,617	3,872	4,324	4,632	4,436	4,366	4,312	4,229	50,475
	b Recoverable Costs Allocated to Demand		38,940	38,938	38,936	40,981	40,977	40,975	40,985	40,978	40,971	40,965	40,959	40,953	485,557
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs (B)		3,870	2,739	4,070	5,557	3,526	3,776	4,231	4,501	4,322	4,249	4,189	4,112	49,143
13	Retail Demand-Related Recoverable Costs (C)		37,854	37,852	37,850	39,838	39,834	39,832	39,830	39,824	39,817	39,811	39,805	39,799	471,946
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		41,724	40,591	41,920	45,395	43,360	43,608	44,061	44,325	44,139	44,059	43,994	43,911	521,088

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 1.0015 Januanry - June; 1.0012 July - December
(C) Line 9b x Line 11.
(D) Line 6 is reported on Schedule 7A.
(E) Line 8 is reported on Schedule 5A.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - December 2017
Return on Working Capital, Amortization Expense
For Project: Regulatory Asset Smith Units 1 & 2
For Retired P.E.s 1413, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1461, 1462, 1468, 1469, 1647, 1620, 1638
(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)	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	
2	Less Amortization (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Net Regulatory Asset Balance (Lines 1 + 2) (A)	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	
4	Average Net Regulatory Asset		21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	21,344,257	
5	Return on Average Net Regulatory Asset														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		113,978	113,978	113,978	124,544	124,544	124,544	124,544	124,544	124,544	124,544	124,544	124,544	1,462,829
	b Debt Component (Line 6 x Debt Component x 1/12)		28,196	28,196	28,196	25,122	25,122	25,122	25,122	25,122	25,122	25,122	25,122	25,122	310,687
6	Amortization Expense														
	a Amortization (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Other (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total System Recoverable Expenses (Lines 5 + 6)		142,174	142,174	142,174	149,666	149,666	149,666	149,666	149,666	149,666	149,666	149,666	149,666	1,773,516
	a Recoverable Costs Allocated to Energy		10,936	10,936	10,936	11,513	11,513	11,513	11,513	11,513	11,513	11,513	11,513	11,513	136,424
	b Recoverable Costs Allocated to Demand		131,238	131,238	131,238	138,153	138,153	138,153	138,153	138,153	138,153	138,153	138,153	138,153	1,637,091
8	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
9	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
10	Retail Energy-Related Recoverable Costs (G)		10,632	10,634	10,642	11,213	11,222	11,229	11,263	11,187	11,217	11,204	11,185	11,193	132,821
11	Retail Demand-Related Recoverable Costs (H)		127,578	127,578	127,578	134,300	134,300	134,300	134,261	134,261	134,261	134,261	134,261	134,261	1,591,201
12	Total Jurisdictional Recoverable Costs (Lines 10 + 11)		138,210	138,211	138,220	145,513	145,523	145,529	145,525	145,448	145,478	145,465	145,446	145,454	1,724,022

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 1.0015 January - June; 1.0012 July - December
(H) Line 7b x Line 9.

Schedule 9A
Page 1 of 2

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2017 - March 2017

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	689,013	34.4399	4.49	1.5473	1.5473	
2	Short-Term Debt	47,101	2.3543	0.54	0.0127	0.0127	
3	Preferred Stock	77,996	3.8986	6.14	0.2396	0.3901	
4	Common Stock	721,314	36.0544	10.25	3.6956	6.0164	
5	Customer Deposits	21,129	1.0561	2.35	0.0248	0.0248	
6	Deferred Taxes	443,726	22.1793				
7	Investment Tax Credit	348	0.0174	7.37	0.0013	0.0019	
8	Total	2,000,628	100.0000		5.5213	7.9932	0.6661
	ITC Component:						
9	Debt	689,013	46.2946	4.49	2.0800	0.0004	
10	Equity-Preferred	77,996	5.2405	6.14	0.3220	0.0001	
11	-Common	721,314	48.4649	10.25	4.9677	0.0014	
12		1,488,323	100.0000		7.3697	0.0019	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.5852	0.1321
14	Total Equity Component (Lines 3, 4, 10, and 11)					6.4080	0.5340
15	Total Revenue Requirement Rate of Return					7.9932	0.6661

Column:
(1) Based on the May 2016 Surveillance Report, Schedule 4.
(2) Column (1) / Total Column (1)
(3) Based on the May 2016 Surveillance Report, Schedule 4.
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

Schedule 9A
Page 2 of 2

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
April 2017 - December 2017

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	743,673	30.7440	4.40	1.3527	1.3527	
2	Short-Term Debt	28,504	1.1784	3.02	0.0356	0.0356	
3	Preferred Stock	94,609	3.9112	6.15	0.2405	0.3915	
4	Common Stock	957,875	39.5993	10.25	4.0589	6.6079	
5	Customer Deposits	24,536	1.0143	2.30	0.0233	0.0233	
6	Deferred Taxes	568,999	23.5229				
7	Investment Tax Credit	721	0.0298	7.61	0.0023	0.0034	
8	Total	2,418,917	100.0000		5.7133	8.4144	0.7012
	ITC Component:						
9	Debt	743,673	41.4036	4.40	1.8218	0.0005	
10	Equity-Preferred	94,609	5.2673	6.15	0.3239	0.0002	
11	-Common	957,875	53.3291	10.25	5.4662	0.0027	
12		1,796,157	100.0000		7.6119	0.0034	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.4121	0.1177
14	Total Equity Component (Lines 3, 4, 10, and 11)					7.0023	0.5835
15	Total Revenue Requirement Rate of Return					8.4144	0.7012

Column:

(1) Based on MFR D-1a in Docket No. 160186-EI with the following adjustments in order to reflect specific terms in the Stipulation and Settlement Agreement under the same Docket.
-Reduced the common equity balance and increased the long-term debt balance in order to calculate a 52.5% equity ratio based on jurisdictional investors sources of capital (long-term debt, short-term debt, preference stock and common equity)

(2) Column (1) / Total Column (1)

(3) Based on MFR D-1a in Docket No. 160186-EI with the following adjustments in order to reflect specific terms in the Stipulation and Settlement Agreement under the same Docket.
-Reduced the common equity cost rate to 10.25%.

(4) Column (2) x Column (3)

(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)

(6) Column (5) / 12

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Scherer/Flint Credit
January 2017 - December 2017

For Project: Scherer - Air Quality Compliance and CCR Programs

P.E.s 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 6756, 6757, 6759, 6764, 6765, CCR-S
(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		50,958	93,736	182,408	477,871	343,980	(140,874)	316,425	303,883	540,032	594,251	627,429	1,652,556	
	b Clearings to Plant		41	0	5,330	1,001	1,119	517,815	41,503	21,474	5,425	1,174	5,454	7,517	
	c Retirements		0	0	2,772	0	0	1,125,362	0	0	0	0	0	0	
	d Cost of Removal		0	0	9,208	65	14,030	30	51	287	2,727	(26)	(8)	76,178	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	139,632,420	139,632,461	139,632,461	139,635,019	139,636,020	139,637,138	139,029,591	182,975,175	182,996,649	183,002,075	183,003,249	183,008,703	183,016,220	
3	Less: Accumulated Depreciation	(16,932,924)	(17,166,015)	(17,399,107)	(17,620,220)	(17,853,251)	(18,072,319)	(17,180,026)	(22,913,396)	(23,221,328)	(23,526,857)	(23,835,148)	(24,143,422)	(24,375,519)	
4	Working Capital (Emissions)	39,415	38,265	38,498	37,231	37,231	36,790	36,047	46,253	45,068	44,056	40,817	38,426	36,232	
5	CWIP - Non Interest Bearing	1,188,133.67	1,239,050	1,332,786	1,509,865	1,986,735	2,329,596	1,670,907	2,473,484	2,755,893	3,290,499	3,883,576	4,505,551	6,150,590	
6	Net Investment (Lines 2 + 3 + 4 + 5)	123,927,045	123,743,760	123,604,638	123,561,895	123,806,734	123,931,206	123,556,519	162,581,516	162,576,282	162,809,773	163,092,493	163,409,258	164,827,523	
7	Average Net Investment		123,835,402	123,674,199	123,583,266	123,684,314	123,868,970	123,743,862	162,577,941	162,578,899	162,693,027	162,951,133	163,250,876	164,118,390	
8	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12)		661,281	660,420	659,935	721,698	722,775	722,045	948,642	948,648	949,314	950,820	952,569	957,631	9,855,778
	b Debt Component (Line 6 x Debt Component x 1/12)		163,587	163,374	163,253	145,576	145,794	145,647	191,354	191,355	191,490	191,793	192,146	193,167	2,078,537
9	Investment Expenses														
	a Depreciation		232,904	232,904	232,904	232,908	232,910	232,912	305,131	305,200	305,236	305,245	305,247	305,256	3,228,755
	b Amortization		188	188	188	188	188	188	247	247	247	247	247	247	2,610
	c Dismantlement		0	0	0	0	0	0	2,773	2,773	2,773	2,773	2,773	2,773	16,636
	d Property Taxes		1,861	1,861	51,905	18,542	18,542	18,542	24,398	24,398	24,398	24,398	36,502	25,664	271,012
	e Other		0	0	0	0	0	0	0	0	0	0	0	0	0
10	O&M and Emissions														
	a O&M Expense		74,942	83,559	80,942	158,534	122,895	113,523	176,576	151,960	134,268	149,849	130,908	123,539	1,501,494
	b Emissions Expense		1,150	(585)	1,267	1,729	834	1,378	2,164	2,182	1,910	3,240	2,836	2,297	20,401
11	Total System Recoverable Expenses (Lines 8+9+10)		1,135,913	1,141,720	1,190,394	1,279,176	1,243,939	1,234,236	1,651,284	1,626,763	1,609,634	1,628,364	1,623,228	1,610,573	16,975,223
	a Recoverable Costs Allocated to Energy		156,706	159,404	167,895	243,820	203,942	198,633	284,179	265,582	239,920	258,730	253,831	223,407	2,656,049
	b Recoverable Costs Allocated to Demand		979,207	982,316	1,022,499	1,035,356	1,039,997	1,035,602	1,367,105	1,361,181	1,369,714	1,369,634	1,369,397	1,387,166	14,319,174
10	Energy Jurisdictional Factor		0.9707242	0.9708493	0.9716585	0.9724822	0.9733005	0.9738746	0.9771750	0.9705037	0.9731720	0.9720224	0.9703311	0.9710743	
11	Demand Jurisdictional Factor		0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	0.9718277	
12	Retail Energy-Related Recoverable Costs		152,347	154,989	163,381	237,466	198,795	193,734	278,026	258,057	233,764	251,793	246,596	217,205	2,586,153
13	Retail Demand-Related Recoverable Costs		951,899	954,922	993,984	1,006,483	1,010,994	1,006,722	1,328,591	1,322,833	1,331,126	1,331,048	1,330,818	1,348,086	13,917,506
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,104,246	1,109,911	1,157,365	1,243,949	1,209,789	1,200,456	1,606,616	1,580,891	1,564,890	1,582,841	1,577,414	1,565,291	16,503,659
15	Scherer/Flint Credit (Line 14 x 24%)		0	0	0	0	0	0	385,588	379,414	375,574	379,882	377,233	375,670	2,273,360

Schedule 1E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2018 - December 2018

Line No.		Period Amount ($)
1	Over/(Under) Recovery for the Current Period (Schedule 2E, Line 5 + 9)	9,258,434
2	Interest Provision (Schedule 2E, Line 6)	178,503
3	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2019 - December 2019 (Lines 1 + 2)	9,436,937

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 32
PARTY: GULF POWER COMPANY (GULF) (DIRECT)
DESCRIPTION: C. Shane Boyett CSB-2

Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)

January 2018 - December 2018
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	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	ECRC Revenues (Net of Revenue Taxes)	19,347,230	12,525,702	12,904,346	12,024,352	16,456,165	19,092,175	20,065,178	19,865,286	17,012,897	14,169,156	12,471,274	13,992,987	189,926,748
2	True-Up Provision (Order No. PSC-2018-0014-FOF-EI)	684,416	684,414	684,414	684,414	684,414	684,414	684,414	684,414	684,414	684,414	684,414	684,414	8,212,970
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	20,031,646	13,210,116	13,588,760	12,708,766	17,140,579	19,776,589	20,749,592	20,549,700	17,697,311	14,853,570	13,155,688	14,677,401	198,139,718
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5E, Line 9)	2,340,398	2,514,023	3,320,895	3,357,958	2,327,291	3,446,632	3,452,907	4,031,768	3,403,885	3,218,676	2,963,732	3,317,526	37,695,691
	b Capital Investment Projects (Schedule 7E, Line 9)	12,695,882	12,689,162	12,708,589	12,702,810	12,718,484	12,743,527	12,472,381	12,468,130	12,473,579	12,492,636	12,507,955	12,512,629	151,185,765
	c **Total Jurisdictional ECRC Costs**	15,036,281	15,203,185	16,029,484	16,060,768	15,045,775	16,190,159	15,925,288	16,499,898	15,877,464	15,711,313	15,471,686	15,830,155	188,881,456
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	4,995,365	(1,993,070)	(2,440,724)	(3,352,002)	2,094,804	3,586,430	4,824,303	4,049,802	1,819,847	(857,742)	(2,315,998)	(1,152,754)	9,258,262
6	Interest Provision (Schedule 3E, Line 10)	17,165	18,452	16,674	12,268	10,257	14,082	15,321	14,622	13,703	14,162	15,858	15,939	178,503
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2017	14,654,926	18,983,040	16,324,008	13,215,544	9,191,396	10,612,224	13,528,311	17,683,522	21,063,533	22,212,670	20,684,675	17,700,122	14,654,926
	b Final True-Up from January 2016 - December 2016 (Order No. PSC-2018-0014-FOF-EI)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)	(3,262,290)
8	True-Up Collected/(Refunded) (see Line 2)	(684,416)	(684,414)	(684,414)	(684,414)	(684,414)	(684,414)	(684,414)	(684,414)	(684,414)	(684,414)	(684,414)	(684,414)	(8,212,970)
9	Adjustments					182	(10)							172
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8 + 9)	15,720,750	13,061,718	9,953,254	5,929,106	7,349,934	10,266,021	14,421,232	17,801,243	18,950,379	17,422,385	14,437,831	12,616,603	12,616,603

Schedule 3E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2018 - December 2018

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 2E, Lines 7a + 7b)	11,392,636	15,720,750	13,061,718	9,953,254	5,929,106	7,349,934	10,266,021	14,421,232	17,801,243	18,950,379	17,422,385	14,437,831	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	15,703,585	13,043,266	9,936,581	5,916,838	7,339,496	10,251,950	14,405,911	17,786,620	18,936,676	17,408,223	14,421,973	12,600,664	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	27,096,220	28,764,016	22,998,299	15,870,093	13,268,602	17,601,884	24,671,932	32,207,852	36,737,919	36,358,602	31,844,358	27,038,495	
4	Average True-Up Amount (Line 3 x 1/2)	13,548,110	14,382,008	11,499,149	7,935,046	6,634,301	8,800,942	12,335,966	16,103,926	18,368,959	18,179,301	15,922,179	13,519,248	
5	Interest Rate (First Day of Reporting Business Month)	0.01580	0.01460	0.01620	0.01860	0.01850	0.01860	0.0112	0.0112	0.0106	0.0073	0.0114	0.0125	
6	Interest Rate (First Day of Subsequent Business Month)	0.01460	0.01620	0.01860	0.01850	0.01860	0.01980	0.0186	0.0106	0.0073	0.0114	0.0125	0.0158	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.03040	0.03080	0.03480	0.03710	0.03710	0.03840	0.0298	0.0218	0.0179	0.0187	0.0239	0.0283	
8	Average Interest Rate (Line 7 x 1/2)	0.01520	0.01540	0.01740	0.01855	0.01855	0.01920	0.01490	0.01090	0.00895	0.00935	0.01195	0.01415	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.00127	0.00128	0.00145	0.00155	0.00155	0.00160	0.00124	0.00091	0.00075	0.00078	0.00100	0.00118	
10	Interest Provision for the Month (Line 4 x Line 9)	17,165	18,452	16,674	12,268	10,257	14,082	15,321	14,622	13,703	14,162	15,858	15,939	178,503

Schedule 4E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2018 - December 2018

Variance Report of O & M Activities
(in Dollars)

Line		(1) Estimated/ Actual	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1	Description of O & M Activities				
.1	Sulfur	0	0	0	0.0 %
.2	Air Emission Fees	243,844	278,972	(35,128)	(12.6) %
.3	Title V	241,993	267,229	(25,237)	(9.4) %
.4	Asbestos Fees	0	1,000	(1,000)	(100.0) %
.5	Emission Monitoring	735,893	740,920	(5,027)	(0.7) %
.6	General Water Quality	2,457,236	2,486,269	(29,033)	(1.2) %
.7	Groundwater Contamination Investigation	3,312,473	3,300,916	11,557	0.4 %
.8	State NPDES Administration	34,500	34,500	0	0.0 %
.9	Lead and Copper Rule	9,134	8,000	1,134	14.2 %
.10	Env Auditing/Assessment	14,454	9,000	5,454	60.6 %
.11	General Solid & Hazardous Waste	1,028,992	1,065,139	(36,147)	(3.4) %
.12	Above Ground Storage Tanks	177,993	223,390	(45,397)	(20.3) %
.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	5,600	10,000	(4,400)	(44.0) %
.17	Gulf Coast Ozone Study	0	0	0	0.0 %
.18	SPCC Substation Project	0	0	0	0.0 %
.19	FDEP NOx Reduction Agreement	951,270	1,001,268	(49,998)	(5.0) %
.20	Air Quality Compliance Program	23,243,117	22,096,267	1,146,850	5.2 %
.21	MACT ICR	0	0	0	0.0 %
.22	Crist Water Conservation	383,227	416,374	(33,147)	(8.0) %
.23	Coal Combustion Residual	6,056,518	12,041,680	(5,985,162)	(49.7) %
.24	Smith Water Conservation	176,492	180,000	(3,508)	(1.9) %
.25	Mercury Allowances	0	0	0	0.0 %
.26	Annual NOx Allowances	19,189	8,926	10,263	115.0 %
.27	Seasonal NOx Allowances	25,638	19,817	5,821	29.4 %
.28	SO2 Allowances	26,796	18,392	8,404	45.7 %
.29	Scherer/Flint Credit - Energy	(399,912)	(445,817)	45,905	(10.3) %
.30	Scherer/Flint Credit - Demand	(6,741)	(11,745)	5,004	(42.6) %
2	Total O & M Activities	38,737,706	43,750,497	(5,012,791)	(11.5) %
3	Recoverable Costs Allocated to Energy	25,093,429	23,995,974	1,097,455	4.6 %
4	Recoverable Costs Allocated to Demand	13,644,277	19,754,523	(6,110,246)	(30.9) %

Notes:
Column (1) is the End of Period Totals on Schedule 5E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-2018-0014-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
January 2018 - December 2018

O & M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected 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	0
. 2	Air Emission Fees	2,792	2,587	115,711	2,279	2,351	2,674	2,575	102,575	2,575	2,575	2,575	2,575	243,844	0	243,844
. 3	Title V	20,984	25,017	19,493	18,659	21,545	25,847	15,997	22,729	17,005	20,052	16,768	17,895	241,993	0	241,993
. 4	Asbestos Fees	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 5	Emission Monitoring	69,483	48,765	110,060	38,115	44,229	62,268	51,905	76,449	52,732	75,593	53,668	52,626	735,893	0	735,893
. 6	General Water Quality	146,302	103,550	129,302	330,697	(17,774)	185,945	279,491	324,417	260,151	249,090	233,385	232,681	2,457,236	2,457,236	0
. 7	Groundwater Contamination Investigation	401,615	140,739	166,540	186,283	169,795	316,698	319,175	335,281	317,999	319,306	321,021	318,020	3,312,473	3,312,473	0
. 8	State NPDES Administration	0	34,500	0	0	0	0	0	0	0	0	0	0	34,500	34,500	0
. 9	Lead & Copper Rule	0	5,136	0	0	0	0	667	667	667	667	667	663	9,134	9,134	0
. 10	Environmental Auditing/Assessment	0	0	571	3,050	1,833	0	0	0	0	4,500	4,500	0	14,454	14,454	0
. 11	General Solid & Hazardous Waste	28,642	61,116	83,135	67,378	61,044	94,609	105,708	114,704	105,838	102,516	102,833	101,469	1,028,992	1,028,992	0
. 12	Above Ground Storage Tanks	414	5,134	6,856	14,108	16,553	7,053	12,896	23,498	27,719	22,900	23,142	17,720	177,993	177,993	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	900	1,200	800	700	1,000	1,000	5,600	0	5,600
. 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	85,898	206,376	(133,684)	55,090	84,916	42,963	92,952	114,350	79,846	122,988	131,292	68,284	951,270	0	951,270
. 20	Air Quality Compliance Program	1,602,788	1,535,307	2,340,635	2,578,831	1,647,622	2,231,708	2,003,552	2,263,209	1,922,877	1,693,810	1,476,685	1,946,094	23,243,117	0	23,243,117
. 21	MACT ICR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 22	Crist Water Conservation	31,860	29,446	35,826	(2,202)	11,394	40,845	40,811	42,443	33,106	34,550	52,894	32,256	383,227	383,227	0
. 23	Coal Combustion Residuals	38,641	401,357	492,070	181,505	363,370	560,068	632,764	733,052	691,761	673,683	647,642	640,606	6,056,518	6,056,518	0
. 24	Smith Water Conservation	7,809	4,384	67,377	3,062	3,312	548	15,000	15,000	15,000	15,000	15,000	15,000	176,492	176,492	0
. 25	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 26	Annual NOx Allowances	3,000	2,225	2,395	1,804	529	830	847	838	805	2,125	1,875	1,917	19,189	0	19,189
. 27	Seasonal NOx Allowances	0	0	0	0	3,471	7,085	5,514	5,574	3,994	0	0	0	25,638	0	25,638
. 28	SO2 Allowances	722	148	105	179	531	1,101	5,258	5,320	4,505	3,531	2,815	2,582	26,796	0	26,796
. 29	Scherer/Flint Credit - Energy	(32,099)	(23,848)	(20,714)	(28,319)	(25,623)	(42,308)	(39,280)	(39,275)	(39,289)	(35,385)	(38,443)	(35,328)	(399,912)	0	(399,912)
. 30	Scherer/Flint Credit - Demand	(550)	2,632	(1,417)	(1,324)	318	(526)	(974)	(977)	(998)	(976)	(978)	(972)	(6,741)	(6,741)	0
2	Total of O & M Activities	2,408,302	2,584,571	3,414,261	3,449,195	2,389,414	3,537,406	3,545,757	4,141,052	3,497,094	3,307,225	3,048,342	3,415,088	38,737,706	13,644,277	25,093,429
3	Recoverable Costs Allocated to Energy	1,753,569	1,796,577	2,434,002	2,666,637	1,779,570	2,332,167	2,140,220	2,552,968	2,045,851	1,885,989	1,648,235	2,057,645	25,093,429		
4	Recoverable Costs Allocated to Demand	654,734	787,994	980,259	782,558	609,844	1,205,239	1,405,537	1,588,084	1,451,243	1,421,235	1,400,106	1,357,443	13,644,277		
5	Retail Energy Jurisdictional Factor	0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069			
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)	1,704,110	1,748,228	2,368,252	2,597,447	1,734,627	2,275,347	2,086,967	2,488,423	1,993,527	1,837,480	1,603,070	1,998,325	24,435,805		
8	Jurisdictional Demand Recoverable Costs (B)	636,288	765,795	952,643	760,511	592,664	1,171,285	1,365,940	1,543,344	1,410,358	1,381,196	1,360,662	1,319,201	13,259,886		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	2,340,398	2,514,023	3,320,895	3,357,958	2,327,291	3,446,632.13	3,452,907	4,031,768	3,403,885	3,218,676	2,963,732	3,317,526	37,695,691		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Schedule 6E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2018 - December 2018

Variance Report of Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		(1) Estimated/ Actual	(2) Original Projection	(3) Variance Amount	(4) Variance Percent	
1	Description of Investment Projects					
.1	Air Quality Assurance Testing	0	0	0	0.0	%
.2	Crist 5, 6 & 7 Precipitator Projects	3,924,055	4,440,147	(516,092)	(11.6)	%
.3	Crist 7 Flue Gas Conditioning	105,621	126,159	(20,538)	(16.3)	%
.4	Low NOx Burners, Crist 6 & 7	1,827,409	2,060,852	(233,443)	(11.3)	%
.5	CEMS - Plants Crist, & Daniel	558,950	666,731	(107,780)	(16.2)	%
.6	Substation Contamination Remediation	239,647	233,944	5,703	2.4	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	13,549	15,084	(1,535)	(10.2)	%
.8	Crist Cooling Tower Cell	37,472	44,758	(7,286)	(16.3)	%
.9	Crist Dechlorination System	25,258	27,378	(2,120)	(7.7)	%
.10	Crist Diesel Fuel Oil Remediation	4,099	4,390	(292)	(6.6)	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	5,387	5,690	(303)	(5.3)	%
.12	Crist IWW Sampling System	3,138	3,311	(174)	(5.2)	%
.13	Sodium Injection System	22,594	24,900	(2,306)	(9.3)	%
.14	Smith Stormwater Collection System	183,780	194,839	(11,059)	(5.7)	%
.15	Smith Waste Water Treatment Facility	34,510	41,673	(7,162)	(17.2)	%
.16	Daniel Ash Management Project	1,337,887	1,396,855	(58,968)	(4.2)	%
.17	Smith Water Conservation	2,178,119	2,717,057	(538,937)	(19.8)	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	11,128,455	12,312,339	(1,183,884)	(9.6)	%
.20	SPCC Compliance	79,591	87,823	(8,232)	(9.4)	%
.21	Crist Common FTIR Monitor	4,752	5,215	(463)	(8.9)	%
.22	Precipitator Upgrades for CAM Compliance	1,188,888	1,317,392	(128,504)	(9.8)	%
.23	Plant Groundwater Contamination	0	0	0	0.0	%
.24	Crist Water Conservation	1,824,743	2,038,329	(213,586)	(10.5)	%
.25	Plant NPDES Permit Compliance Projects	529,219	551,628	(22,408)	(4.1)	%
.26	Air Quality Compliance Program	130,047,019	144,660,231	(14,613,212)	(10.1)	%
.27	General Water Quality	79,781	117,500	(37,719)	(32.1)	%
.28	Coal Combustion Residual	122,585	1,022,097	(899,512)	(88.0)	%
.29	Effluent Limitations Guidelines	576,620	688,046	(111,426)	(16.2)	%
.30	Mercury Allowances	0	0	0	0.0	%
.31	Annual NOx Allowances	1,158	2,150	(992)	(46.1)	%
.32	Seasonal NOx Allowances	1,628	3,105	(1,478)	(47.6)	%
.33	SO2 Allowances	445,032	530,502	(85,470)	(16.1)	%
.34	Regulatory Asset Smith Units 1 & 2	2,876,907	3,159,075	(282,168)	(8.9)	%
.35	Scherer/Flint Credit - Energy	(297,126)	(342,511)	45,385	13.3	%
.36	Scherer/Flint Credit - Demand	(3,565,508)	(4,110,128)	544,621	13.3	%
2	Total Investment Projects - Recoverable Costs	155,545,219	174,046,561	(18,501,342)	(10.6)	%
3	Recoverable Costs Allocated to Energy	11,965,017	13,388,197	(1,423,180)	(10.6)	%
4	Recoverable Costs Allocated to Demand	143,580,202	160,658,364	(17,078,162)	(10.6)	%

Notes:
Column (1) is the End of Period Totals on Schedule 7E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-2018-0014-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Schedule 7E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
January 2018 - December 2018

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected 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	0	0	0	0	0	0	0	0	0	0	0
. 2	Crist 5, 6 & 7 Precipitator Projects	334,575	333,911	333,246	332,582	331,918	331,253	322,696	322,056	321,415	320,775	320,134	319,494	3,924,055	3,622,205	301,850
. 3	Crist 7 Flue Gas Conditioning	8,963	8,963	8,963	8,963	8,963	8,963	8,641	8,641	8,641	8,641	8,641	8,641	105,621	97,497	8,125
. 4	Low NOx Burners, Crist 6 & 7	154,826	154,551	154,276	154,419	154,663	154,982	150,874	150,296	150,030	149,764	149,497	149,231	1,827,409	1,686,839	140,570
. 5	CEMS - Plants Crist & Daniel	47,767	47,823	47,489	47,131	47,242	47,153	45,941	45,854	45,767	45,681	45,594	45,508	558,950	515,954	42,996
. 6	Substation Contamination Remediation	17,736	17,700	17,664	17,628	17,591	17,555	17,986	19,710	21,434	23,157	24,881	26,605	239,647	221,212	18,434
. 7	Raw Water Well Flowmeters - Plants Crist & Smith	1,157	1,154	1,151	1,148	1,145	1,142	1,116	1,113	1,110	1,107	1,104	1,102	13,549	12,506	1,042
. 8	Crist Cooling Tower Cell	3,180	3,180	3,180	3,180	3,180	3,180	3,065	3,065	3,065	3,065	3,065	3,065	37,472	34,590	2,882
. 9	Crist Dechlorination System	2,161	2,154	2,146	2,139	2,131	2,124	2,085	2,078	2,071	2,064	2,056	2,049	25,258	23,315	1,943
. 10	Crist Diesel Fuel Oil Remediation	351	350	348	347	346	344	339	337	336	335	334	332	4,099	3,784	315
. 11	Crist Bulk Tanker Unloading Secondary Containment	462	460	458	456	454	452	446	444	442	440	438	436	5,387	4,972	414
. 12	Crist IWW Sampling System	269	268	267	266	264	263	260	259	257	256	255	254	3,138	2,896	241
. 13	Sodium Injection System	1,931	1,925	1,919	1,914	1,908	1,903	1,863	1,857	1,852	1,846	1,841	1,835	22,594	20,856	1,738
. 14	Smith Stormwater Collection System	15,749	15,685	15,620	15,556	15,491	15,427	15,198	15,135	15,073	15,011	14,949	14,887	183,780	169,643	14,137
. 15	Smith Waste Water Treatment Facility	2,054	2,050	2,046	2,042	2,498	2,990	3,024	3,106	3,102	3,098	3,648	4,852	34,510	31,856	2,655
. 16	Daniel Ash Management Project	115,442	115,219	114,996	107,611	112,759	112,535	110,426	110,211	109,995	109,780	109,564	109,349	1,337,887	1,234,973	102,914
. 17	Smith Water Conservation	181,537	182,754	183,477	183,623	183,744	182,523	177,831	178,537	179,243	179,950	181,376	183,523	2,178,119	2,010,571	167,548
. 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	937,862	936,429	935,245	937,655	937,822	944,276	922,982	919,682	917,318	915,184	913,051	910,950	11,128,455	10,272,420	856,035
. 20	SPCC Compliance	6,800	6,781	6,761	6,742	6,723	6,703	6,560	6,542	6,523	6,504	6,485	6,467	79,591	73,469	6,122
. 21	Crist Common FTIR Monitor	406	405	404	402	401	400	392	391	389	388	387	386	4,752	4,386	366
. 22	Precipitator Upgrades for CAM Compliance	101,543	101,275	101,007	100,723	100,439	100,163	97,955	97,689	97,423	97,157	96,890	96,624	1,188,888	1,097,435	91,453
. 23	Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 24	Crist Water Conservation	155,319	155,657	155,261	153,564	153,186	152,819	149,326	148,948	149,291	150,354	150,697	150,320	1,824,743	1,684,378	140,365
. 25	Plant NPDES Permit Compliance Projects	42,685	42,563	42,460	42,400	42,367	42,316	41,920	43,793	46,238	47,418	47,589	47,471	529,219	488,510	40,709
. 26	Air Quality Compliance Program	11,018,769	11,005,809	11,001,332	10,993,809	10,988,735	10,988,257	10,728,780	10,704,354	10,684,788	10,664,387	10,644,061	10,623,938	130,047,019	120,043,401	10,003,617
. 27	General Water Quality	4,979	4,979	4,979	4,979	4,979	4,979	7,829	8,101	8,085	8,070	8,630	9,191	79,781	73,644	6,137
. 28	Coal Combustion Residuals	(87,907)	(80,833)	(70,275)	(59,935)	(43,446)	(20,815)	6,207	29,383	55,109	96,531	135,453	163,113	122,585	113,156	9,430
. 29	Steam Electric Effluent Limitations Guidelines	33,306	33,306	51,608	51,486	51,673	52,013	50,775	50,667	50,753	50,452	50,344	50,237	576,620	532,264	44,355
. 30	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 31	Annual NOx Allowances	151	136	122	110	103	98	90	85	81	72	61	50	1,158	1,069	89
. 32	Seasonal NOx Allowances	218	218	218	218	166	131	127	96	68	56	56	56	1,628	1,503	125
. 33	SO2 Allowances	37,820	37,818	37,817	37,816	37,810	37,801	36,423	36,392	36,364	36,341	36,323	36,307	445,032	410,799	34,233
. 34	Regulatory Asset Sminth Units 1 & 2	245,822	245,112	244,403	243,694	242,985	242,276	237,144	236,461	235,777	235,094	234,411	233,727	2,876,907	2,655,606	221,301
. 35	Scherer/Flint Credit - Energy	(24,768)	(24,777)	(24,830)	(24,917)	(24,929)	(25,016)	(24,438)	(24,512)	(24,577)	(24,668)	(24,773)	(24,921)	(297,126)	0	(297,126)
. 36	Scherer/Flint Credit - Demand	(297,211)	(297,318)	(297,959)	(299,000)	(299,150)	(300,192)	(293,260)	(294,138)	(294,928)	(296,019)	(297,281)	(299,053)	(3,565,508)	(3,565,508)	0
2	Total Investment Projects - Recoverable Costs	13,063,956	13,055,706	13,075,798	13,068,749	13,084,159	13,108,997	12,830,601	12,826,634	12,832,538	12,852,291	12,869,763	12,876,026	155,545,219	143,580,202	11,965,017
3	Recoverable Costs Allocated to Energy	1,004,920	1,004,285	1,005,831	1,005,288	1,006,474	1,008,384	986,969	986,664	987,118	988,638	989,982	990,464	11,965,017		
4	Recoverable Costs Allocated to Demand	12,059,037	12,051,420	12,069,967	12,063,461	12,077,685	12,100,612	11,843,632	11,839,970	11,845,419	11,863,654	11,879,781	11,885,563	143,580,202		
5	Retail Energy Jurisdictional Factor	0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069			
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)	976,576	977,258	978,660	979,205	981,055	983,817	962,412	961,719	961,872	963,209	962,854	961,909	11,650,547		
8	Jurisdictional Demand Recoverable Costs (C)	11,719,306	11,711,904	11,729,929	11,723,605	11,737,429	11,759,710	11,509,970	11,506,411	11,511,707	11,529,427	11,545,101	11,550,719	139,535,217		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	12,695,882	12,689,162	12,708,589	12,702,810	12,718,484	12,743,527	12,472,381	12,468,130	12,473,579	12,492,636	12,507,955	12,512,629	151,185,765		

Notes:
(A) Pages 1-29 of Schedule 8E, Line 9, Pages 30-33 of Schedule 8E, Line 6, Page 34, Line 7, Schedule, 10E,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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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) PEs 1006 & 1244 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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	
3	Less: Accumulated Depreciation (C)	3,755,279	3,644,143	3,533,008	3,421,873	3,310,738	3,199,603	3,088,468	2,977,332	2,866,197	2,755,062	2,643,927	2,532,792	2,421,657	
4	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)	37,432,602	37,321,467	37,210,331	37,099,196	36,988,061	36,876,926	36,765,791	36,654,656	36,543,520	36,432,385	36,321,250	36,210,115	36,098,980	
6	Average Net Investment		37,377,034	37,265,899	37,154,764	37,043,629	36,932,493	36,821,358	36,710,223	36,599,088	36,487,953	36,376,818	36,265,682	36,154,547	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		179,447	178,914	178,380	177,846	177,313	176,779	169,638	169,124	168,611	168,097	167,584	167,070	2,078,804
	b Debt Component (Line 6 x Debt Component x 1/12)		43,993	43,862	43,731	43,600	43,470	43,339	41,923	41,796	41,669	41,542	41,415	41,288	511,629
8	Investment Expenses														
	a Depreciation (E)		111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	1,333,622
	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 (Lines 7 + 8)		334,575	333,911	333,246	332,582	331,918	331,253	322,696	322,056	321,415	320,775	320,134	319,494	3,924,055
	a Recoverable Costs Allocated to Energy		25,737	25,685	25,634	25,583	25,532	25,481	24,823	24,774	24,724	24,675	24,626	24,576	301,850
	b Recoverable Costs Allocated to Demand		308,839	308,225	307,612	306,999	306,385	305,772	297,873	297,282	296,691	296,100	295,509	294,917	3,622,205
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		25,011	24,994	24,942	24,919	24,887	24,860	24,205	24,147	24,092	24,040	23,951	23,868	293,917
13	Retail Demand-Related Recoverable Costs (I)		300,138	299,542	298,946	298,350	297,754	297,158	289,482	288,907	288,333	287,758	287,183	286,609	3,520,159
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		325,149	324,536	323,888	323,269	322,641	322,018	313,687	313,054	312,424	311,798	311,134	310,477	3,814,076

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)		7,198	7,198	7,198	7,198	7,198	7,198	6,928	6,928	6,928	6,928	6,928	6,928	84,760
	b Debt Component (Line 6 x Debt Component x 1/12)		1,765	1,765	1,765	1,765	1,765	1,765	1,712	1,712	1,712	1,712	1,712	1,712	20,862
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)		8,963	8,963	8,963	8,963	8,963	8,963	8,641	8,641	8,641	8,641	8,641	8,641	105,621
	a Recoverable Costs Allocated to Energy		689	689	689	689	689	689	665	665	665	665	665	665	8,125
	b Recoverable Costs Allocated to Demand		8,273	8,273	8,273	8,273	8,273	8,273	7,976	7,976	7,976	7,976	7,976	7,976	97,497
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		670	671	671	672	672	673	648	648	648	648	646	645	7,911
13	Retail Demand-Related Recoverable Costs (I)		8,040	8,040	8,040	8,040	8,040	8,040	7,751	7,751	7,751	7,751	7,751	7,751	94,750
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,710	8,711	8,711	8,712	8,712	8,713	8,399	8,399	8,399	8,399	8,398	8,397	102,661

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	140,000	0	9,123	0	0	0	0	0	0	149,123
	b Clearings to Plant		0	0	0	0	140,000	9,123	0	0	0	0	0	0	149,123
	c Retirements		0	0	0	0	0	0	94,066	0	0	0	0	0	94,066
	d Cost of Removal		0	0	0	0	33,650	1,911	0	0	0	0	0	0	35,561
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,579,202	13,579,202	13,579,202	13,579,202	13,579,202	13,719,202	13,728,324	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	
3	Less: Accumulated Depreciation (C)	4,640,203	4,594,155	4,548,106	4,502,058	4,456,010	4,443,611	4,399,012	4,446,537	4,400,307	4,354,077	4,307,847	4,261,617	4,215,387	
4	CWIP - Non Interest Bearing	0	0	0	0	140,000	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	18,219,405	18,173,356	18,127,308	18,081,260	18,175,211	18,162,813	18,127,336	18,080,796	18,034,566	17,988,336	17,942,105	17,895,875	17,849,645	
6	Average Net Investment		18,196,381	18,150,332	18,104,284	18,128,235	18,169,012	18,145,074	18,104,066	18,057,681	18,011,451	17,965,220	17,918,990	17,872,760	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		87,361	87,140	86,919	87,034	87,229	87,115	83,659	83,445	83,231	83,017	82,804	82,590	1,021,542
	b Debt Component (Line 6 x Debt Component x 1/12)		21,417	21,363	21,309	21,337	21,385	21,357	20,675	20,622	20,569	20,516	20,463	20,411	251,424
8	Investment Expenses														
	a Depreciation (E)		44,337	44,337	44,337	44,337	44,337	44,799	44,829	44,519	44,519	44,519	44,519	44,519	533,906
	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)		154,826	154,551	154,276	154,419	154,663	154,982	150,874	150,296	150,030	149,764	149,497	149,231	1,827,409
	a Recoverable Costs Allocated to Energy		11,910	11,889	11,867	11,878	11,897	11,922	11,606	11,561	11,541	11,520	11,500	11,479	140,570
	b Recoverable Costs Allocated to Demand		142,917	142,663	142,408	142,541	142,766	143,060	139,269	138,735	138,489	138,243	137,997	137,751	1,686,839
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		11,574	11,569	11,547	11,570	11,597	11,631	11,317	11,269	11,246	11,224	11,185	11,148	136,876
13	Retail Demand-Related Recoverable Costs (I)		138,890	138,643	138,396	138,525	138,744	139,030	135,345	134,827	134,588	134,349	134,110	133,871	1,639,317
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		150,464	150,212	149,943	150,095	150,340	150,661	146,662	146,096	145,833	145,573	145,294	145,019	1,776,193

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) 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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist & Daniel
P.E.s 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1312, 1316, 1323, 1324, 1325, 1357, 1358, 1364, 1558, 1570, 1592, 1658, 1829, 1830
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		5	(0)	(1)	(0)	0	1	0	0	0	0	0	0	4
	b Clearings to Plant		44,548	(0)	(1)	(0)	0	1	0	0	0	0	0	0	44,548
	c Retirements		0	73,800	0	0	0	0	0	0	0	0	0	0	73,800
	d Cost of Removal		0	(33)	0	0	0	0	0	0	0	0	0	0	(33)
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	4,719,852	4,764,400	4,690,600	4,690,599	4,690,599	4,690,599	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	
3	Less: Accumulated Depreciation (C)	553,970	538,862	597,373	582,362	567,350	552,339	537,327	522,316	507,304	492,293	477,281	462,270	447,258	
4	CWIP - Non Interest Bearing	44,543	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	5,318,365	5,303,262	5,287,973	5,272,961	5,257,949	5,242,938	5,227,927	5,212,916	5,197,904	5,182,893	5,167,881	5,152,870	5,137,858	
6	Average Net Investment		5,310,813	5,295,618	5,280,467	5,265,455	5,250,444	5,235,433	5,220,422	5,205,410	5,190,399	5,175,387	5,160,376	5,145,364	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		25,497	25,424	25,352	25,279	25,207	25,135	24,124	24,054	23,985	23,915	23,846	23,777	295,596
	b Debt Component (Line 6 x Debt Component x 1/12)		6,251	6,233	6,215	6,197	6,180	6,162	5,962	5,945	5,927	5,910	5,893	5,876	72,751
8	Investment Expenses														
	a Depreciation (E)		15,108	15,255	15,011	15,011	15,011	15,011	15,011	15,011	15,011	15,011	15,011	15,011	180,478
	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		911	911	911	642	844	844	844	844	844	844	844	844	10,125
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		47,767	47,823	47,489	47,131	47,242	47,153	45,941	45,854	45,767	45,681	45,594	45,508	558,950
	a Recoverable Costs Allocated to Energy		3,674	3,679	3,653	3,625	3,634	3,627	3,534	3,527	3,521	3,514	3,507	3,501	42,996
	b Recoverable Costs Allocated to Demand		44,093	44,144	43,836	43,505	43,608	43,526	42,407	42,327	42,247	42,167	42,087	42,007	515,954
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		3,571	3,580	3,554	3,531	3,542	3,539	3,446	3,438	3,431	3,424	3,411	3,400	41,866
13	Retail Demand-Related Recoverable Costs (I)		42,850	42,901	42,601	42,280	42,380	42,299	41,212	41,134	41,057	40,979	40,902	40,824	501,418
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		46,421	46,480	46,155	45,811	45,922	45,838	44,658	44,572	44,487	44,403	44,313	44,224	543,285

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist $4,135,480; Daniel $584,373. Ending Balances: Crist $4,106,227; Daniel $584,373.
(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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Substation Contamination Remediation
P.E.s 1007, 2859, 3400, 3412, 3463, 3477
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	305,166	305,166	305,166	305,166	305,166	305,170	1,831,000
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	2,483,333	
3	Less: Accumulated Depreciation (C)	(525,405)	(531,455)	(537,505)	(543,554)	(549,604)	(555,654)	(561,703)	(567,753)	(573,803)	(579,852)	(585,902)	(591,952)	(598,002)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	305,166	610,332	915,498	1,220,664	1,525,830	1,831,000	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,957,928	1,951,878	1,945,829	1,939,779	1,933,729	1,927,680	1,921,630	2,220,746	2,519,863	2,818,979	3,118,095	3,417,212	3,716,332	
6	Average Net Investment		1,954,903	1,948,853	1,942,804	1,936,754	1,930,704	1,924,655	2,071,188	2,370,304	2,669,421	2,968,537	3,267,653	3,566,772	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		9,385	9,356	9,327	9,298	9,269	9,240	9,571	10,953	12,335	13,718	15,100	16,482	134,036
	b Debt Component (Line 6 x Debt Component x 1/12)		2,301	2,294	2,287	2,280	2,272	2,265	2,365	2,707	3,048	3,390	3,732	4,073	33,014
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	6,050	6,050	72,596
	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)		17,736	17,700	17,664	17,628	17,591	17,555	17,986	19,710	21,434	23,157	24,881	26,605	239,647
	a Recoverable Costs Allocated to Energy		1,364	1,362	1,359	1,356	1,353	1,350	1,384	1,516	1,649	1,781	1,914	2,047	18,434
	b Recoverable Costs Allocated to Demand		16,372	16,338	16,305	16,272	16,238	16,205	16,602	18,194	19,785	21,376	22,967	24,558	221,212
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		1,326	1,325	1,322	1,321	1,319	1,318	1,349	1,478	1,607	1,736	1,861	1,988	17,948
13	Retail Demand-Related Recoverable Costs (I)		15,911	15,878	15,846	15,813	15,781	15,748	16,135	17,681	19,227	20,774	22,320	23,867	214,980
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		17,236	17,203	17,168	17,134	17,100	17,066	17,484	19,159	20,834	22,509	24,182	25,854	232,928

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E.s 1155 & 1606
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(38,973)	(39,468)	(39,963)	(40,458)	(40,953)	(41,447)	(41,942)	(42,437)	(42,932)	(43,427)	(43,922)	(44,416)	(44,911)	
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) (A)	110,976	110,482	109,987	109,492	108,997	108,502	108,007	107,513	107,018	106,523	106,028	105,533	105,038	
6	Average Net Investment		110,729	110,234	109,739	109,244	108,750	108,255	107,760	107,265	106,770	106,275	105,781	105,286	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		532	529	527	524	522	520	498	496	493	491	489	487	6,107
	b Debt Component (Line 6 x Debt Component x 1/12)		130	130	129	129	128	127	123	122	122	121	121	120	1,503
8	Investment Expenses														
	a Depreciation (E)		495	495	495	495	495	495	495	495	495	495	495	495	5,938
	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)		1,157	1,154	1,151	1,148	1,145	1,142	1,116	1,113	1,110	1,107	1,104	1,102	13,549
	a Recoverable Costs Allocated to Energy		89	89	89	88	88	88	86	86	85	85	85	85	1,042
	b Recoverable Costs Allocated to Demand		1,068	1,065	1,062	1,060	1,057	1,054	1,030	1,027	1,025	1,022	1,019	1,017	12,506
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		86	86	86	86	86	86	84	83	83	83	83	82	1,015
13	Retail Demand-Related Recoverable Costs (I)		1,038	1,035	1,032	1,030	1,027	1,024	1,001	998	996	993	991	988	12,154
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,124	1,121	1,119	1,116	1,113	1,110	1,085	1,082	1,079	1,076	1,073	1,070	13,169

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)		2,554	2,554	2,554	2,554	2,554	2,554	2,458	2,458	2,458	2,458	2,458	2,458	30,071
	b Debt Component (Line 6 x Debt Component x 1/12)		626	626	626	626	626	626	607	607	607	607	607	607	7,401
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)		3,180	3,180	3,180	3,180	3,180	3,180	3,065	3,065	3,065	3,065	3,065	3,065	37,472
	a Recoverable Costs Allocated to Energy		245	245	245	245	245	245	236	236	236	236	236	236	2,882
	b Recoverable Costs Allocated to Demand		2,935	2,935	2,935	2,935	2,935	2,935	2,830	2,830	2,830	2,830	2,830	2,830	34,590
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		238	238	238	238	238	239	230	230	230	230	229	229	2,807
13	Retail Demand-Related Recoverable Costs (I)		2,853	2,853	2,853	2,853	2,853	2,853	2,750	2,750	2,750	2,750	2,750	2,750	33,615
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,090	3,091	3,091	3,091	3,091	3,091	2,980	2,980	2,980	2,980	2,979	2,979	36,422

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Dechlorination System
P.E.s 1180 & 1248
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(228,692)	(229,949)	(231,205)	(232,461)	(233,718)	(234,974)	(236,230)	(237,486)	(238,743)	(239,999)	(241,255)	(242,512)	(243,768)	
4	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)	152,005	150,748	149,492	148,236	146,980	145,723	144,467	143,211	141,954	140,698	139,442	138,185	136,929	
6	Average Net Investment		151,377	150,120	148,864	147,608	146,351	145,095	143,839	142,582	141,326	140,070	138,814	137,557	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		727	721	715	709	703	697	665	659	653	647	641	636	8,171
	b Debt Component (Line 6 x Debt Component x 1/12)		178	177	175	174	172	171	164	163	161	160	159	157	2,011
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	1,256	1,256	15,076
	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)		2,161	2,154	2,146	2,139	2,131	2,124	2,085	2,078	2,071	2,064	2,056	2,049	25,258
	a Recoverable Costs Allocated to Energy		166	166	165	165	164	163	160	160	159	159	158	158	1,943
	b Recoverable Costs Allocated to Demand		1,995	1,988	1,981	1,974	1,967	1,960	1,925	1,918	1,911	1,905	1,898	1,891	23,315
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		162	161	161	160	160	159	156	156	155	155	154	153	1,892
13	Retail Demand-Related Recoverable Costs (I)		1,939	1,932	1,925	1,919	1,912	1,905	1,871	1,864	1,858	1,851	1,845	1,838	22,658
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,100	2,093	2,086	2,079	2,072	2,064	2,027	2,020	2,013	2,006	1,998	1,991	24,550

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(48,131)	(48,358)	(48,586)	(48,813)	(49,041)	(49,268)	(49,495)	(49,723)	(49,950)	(50,178)	(50,405)	(50,633)	(50,860)	
4	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)	20,792	20,565	20,337	20,110	19,882	19,655	19,428	19,200	18,973	18,745	18,518	18,290	18,063	
6	Average Net Investment		20,679	20,451	20,224	19,996	19,769	19,541	19,314	19,086	18,859	18,632	18,404	18,177	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		99	98	97	96	95	94	89	88	87	86	85	84	1,099
	b Debt Component (Line 6 x Debt Component x 1/12)		24	24	24	24	23	23	22	22	22	21	21	21	270
8	Investment Expenses														
	a Depreciation (E)		227	227	227	227	227	227	227	227	227	227	227	227	2,729
	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)		351	350	348	347	346	344	339	337	336	335	334	332	4,099
	a Recoverable Costs Allocated to Energy		27	27	27	27	27	26	26	26	26	26	26	26	315
	b Recoverable Costs Allocated to Demand		324	323	322	320	319	318	313	311	310	309	308	307	3,784
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		26	26	26	26	26	26	25	25	25	25	25	25	307
13	Retail Demand-Related Recoverable Costs (I)		315	314	312	311	310	309	304	303	302	300	299	298	3,677
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		341	340	339	337	336	335	329	328	327	325	324	323	3,984

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unloading Secondary Containment
P.E. 1271
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(80,089)	(80,424)	(80,759)	(81,094)	(81,429)	(81,764)	(82,099)	(82,434)	(82,769)	(83,104)	(83,439)	(83,774)	(84,109)	
4	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)	21,406	21,071	20,736	20,401	20,066	19,731	19,396	19,061	18,726	18,391	18,056	17,721	17,387	
6	Average Net Investment		21,238	20,903	20,568	20,233	19,899	19,564	19,229	18,894	18,559	18,224	17,889	17,554	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		102	100	99	97	96	94	89	87	86	84	83	81	1,098
	b Debt Component (Line 6 x Debt Component x 1/12)		25	25	24	24	23	23	22	22	21	21	20	20	270
8	Investment Expenses														
	a Depreciation (E)		335	335	335	335	335	335	335	335	335	335	335	335	4,019
	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		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)		462	460	458	456	454	452	446	444	442	440	438	436	5,387
	a Recoverable Costs Allocated to Energy		36	35	35	35	35	35	34	34	34	34	34	34	414
	b Recoverable Costs Allocated to Demand		426	425	423	421	419	417	411	410	408	406	404	403	4,972
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		35	34	34	34	34	34	33	33	33	33	33	33	403
13	Retail Demand-Related Recoverable Costs (I)		414	413	411	409	407	405	400	398	396	395	393	391	4,832
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		449	447	445	443	441	439	433	431	430	428	426	424	5,236

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(47,303)	(47,500)	(47,696)	(47,893)	(48,089)	(48,286)	(48,482)	(48,679)	(48,875)	(49,072)	(49,268)	(49,465)	(49,661)	
4	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)	12,239	12,043	11,846	11,650	11,453	11,257	11,060	10,864	10,668	10,471	10,275	10,078	9,882	
6	Average Net Investment		12,141	11,945	11,748	11,552	11,355	11,159	10,962	10,766	10,569	10,373	10,176	9,980	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		58	57	56	55	55	54	51	50	49	48	47	46	626
	b Debt Component (Line 6 x Debt Component x 1/12)		14	14	14	14	13	13	13	12	12	12	12	11	154
8	Investment Expenses														
	a Depreciation (E)		196	196	196	196	196	196	196	196	196	196	196	196	2,358
	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)		269	268	267	266	264	263	260	259	257	256	255	254	3,138
	a Recoverable Costs Allocated to Energy		21	21	21	20	20	20	20	20	20	20	20	20	241
	b Recoverable Costs Allocated to Demand		248	247	246	245	244	243	240	239	238	237	236	234	2,896
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		20	20	20	20	20	20	19	19	19	19	19	19	235
13	Retail Demand-Related Recoverable Costs (I)		241	240	239	238	237	236	233	232	231	230	229	228	2,815
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		261	260	259	258	257	256	252	251	250	249	248	247	3,050

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(118,310)	(119,249)	(120,188)	(121,127)	(122,067)	(123,006)	(123,945)	(124,884)	(125,824)	(126,763)	(127,702)	(128,641)	(129,581)	
4	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)	166,312	165,373	164,434	163,494	162,555	161,616	160,677	159,737	158,798	157,859	156,920	155,980	155,041	
6	Average Net Investment		165,843	164,903	163,964	163,025	162,086	161,146	160,207	159,268	158,329	157,389	156,450	155,511	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		796	792	787	783	778	774	740	736	732	727	723	719	9,086
	b Debt Component (Line 6 x Debt Component x 1/12)		195	194	193	192	191	190	183	182	181	180	179	178	2,236
8	Investment Expenses														
	a Depreciation (E)		939	939	939	939	939	939	939	939	939	939	939	939	11,271
	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)		1,931	1,925	1,919	1,914	1,908	1,903	1,863	1,857	1,852	1,846	1,841	1,835	22,594
	a Recoverable Costs Allocated to Energy		149	148	148	147	147	146	143	143	142	142	142	141	1,738
	b Recoverable Costs Allocated to Demand		1,782	1,777	1,772	1,767	1,761	1,756	1,719	1,714	1,709	1,704	1,699	1,694	20,856
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		144	144	144	143	143	143	140	139	139	138	138	137	1,692
13	Retail Demand-Related Recoverable Costs (I)		1,732	1,727	1,722	1,717	1,712	1,707	1,671	1,666	1,661	1,656	1,651	1,647	20,268
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,876	1,871	1,866	1,860	1,855	1,850	1,811	1,805	1,800	1,795	1,789	1,784	21,960

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(1,927,957)	(1,938,738)	(1,949,519)	(1,960,300)	(1,971,081)	(1,981,863)	(1,992,644)	(2,003,425)	(2,014,206)	(2,024,987)	(2,035,768)	(2,046,549)	(2,057,330)	
4	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)	836,422	825,640	814,859	804,078	793,297	782,516	771,735	760,954	750,173	739,392	728,611	717,830	707,049	
6	Average Net Investment		831,031	820,250	809,469	798,688	787,907	777,126	766,344	755,563	744,782	734,001	723,220	712,439	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,990	3,938	3,886	3,834	3,783	3,731	3,541	3,491	3,442	3,392	3,342	3,292	43,663
	b Debt Component (Line 6 x Debt Component x 1/12)		978	965	953	940	927	915	875	863	851	838	826	814	10,745
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	10,781	10,781	129,373
	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)		15,749	15,685	15,620	15,556	15,491	15,427	15,198	15,135	15,073	15,011	14,949	14,887	183,780
	a Recoverable Costs Allocated to Energy		1,211	1,207	1,202	1,197	1,192	1,187	1,169	1,164	1,159	1,155	1,150	1,145	14,137
	b Recoverable Costs Allocated to Demand		14,538	14,478	14,419	14,359	14,300	14,240	14,028	13,971	13,914	13,856	13,799	13,742	169,643
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		1,177	1,174	1,169	1,166	1,162	1,158	1,140	1,135	1,130	1,125	1,118	1,112	13,765
13	Retail Demand-Related Recoverable Costs (I)		14,128	14,070	14,012	13,955	13,897	13,839	13,633	13,578	13,522	13,466	13,410	13,355	164,864
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		15,305	15,244	15,181	15,120	15,058	14,997	14,773	14,712	14,652	14,591	14,529	14,467	178,630

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E.s 1466 & 1643
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	153,967	11,936	30,000	0	0	0	192,000	25,000	412,903
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	150,000	0	150,000
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	328,962	328,962	
3	Less: Accumulated Depreciation (C)	48,283	47,585	46,887	46,189	45,491	44,793	44,095	43,397	42,699	42,001	41,303	40,605	39,323	
4	CWIP - Non Interest Bearing	0	0	0	0	0	153,967	165,903	195,903	195,903	195,903	195,903	237,903	262,903	
5	Net Investment (Lines 2 + 3 + 4) (A)	227,245	226,547	225,849	225,151	224,453	377,722	388,960	418,262	417,564	416,866	416,168	607,471	631,188	
6	Average Net Investment		226,896	226,198	225,500	224,802	301,088	383,341	403,611	417,913	417,215	416,517	511,819	619,329	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,089	1,086	1,083	1,079	1,446	1,840	1,865	1,931	1,928	1,925	2,365	2,862	20,499
	b Debt Component (Line 6 x Debt Component x 1/12)		267	266	265	265	354	451	461	477	476	476	584	707	5,051
8	Investment Expenses														
	a Depreciation (E)		698	698	698	698	698	698	698	698	698	698	698	1,283	8,960
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,054	2,050	2,046	2,042	2,498	2,990	3,024	3,106	3,102	3,098	3,648	4,852	34,510
	a Recoverable Costs Allocated to Energy		158	158	157	157	192	230	233	239	239	238	281	373	2,655
	b Recoverable Costs Allocated to Demand		1,896	1,892	1,889	1,885	2,306	2,760	2,791	2,867	2,864	2,860	3,367	4,479	31,856
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		154	153	153	153	187	224	227	233	233	232	273	362	2,585
13	Retail Demand-Related Recoverable Costs (I)		1,843	1,839	1,835	1,832	2,241	2,682	2,713	2,787	2,783	2,779	3,272	4,353	30,958
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,996	1,993	1,989	1,985	2,428	2,906	2,940	3,020	3,016	3,012	3,545	4,715	33,543

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E.s 1501, 1535, 1555, 1819
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	
3	Less: Accumulated Depreciation (C)	(5,936,185)	(5,973,560)	(6,010,936)	(6,048,311)	(6,085,686)	(6,123,062)	(6,160,437)	(6,197,812)	(6,235,187)	(6,272,563)	(6,309,938)	(6,347,313)	(6,384,689)	
4	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)	9,013,939	8,976,564	8,939,188	8,901,813	8,864,438	8,827,062	8,789,687	8,752,312	8,714,937	8,677,561	8,640,186	8,602,811	8,565,435	
6	Average Net Investment		8,995,251	8,957,876	8,920,501	8,883,125	8,845,750	8,808,375	8,771,000	8,733,624	8,696,249	8,658,874	8,621,498	8,584,123	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		43,186	43,007	42,827	42,648	42,468	42,289	40,531	40,358	40,185	40,013	39,840	39,667	497,020
	b Debt Component (Line 6 x Debt Component x 1/12)		10,587	10,543	10,499	10,455	10,411	10,367	10,016	9,974	9,931	9,888	9,846	9,803	122,323
8	Investment Expenses														
	a Depreciation (E)		37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	448,504
	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		24,294	24,294	24,294	17,133	22,503	22,503	22,503	22,503	22,503	22,503	22,503	22,503	270,040
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		115,442	115,219	114,996	107,611	112,759	112,535	110,426	110,211	109,995	109,780	109,564	109,349	1,337,887
	a Recoverable Costs Allocated to Energy		8,880	8,863	8,846	8,278	8,674	8,657	8,494	8,478	8,461	8,445	8,428	8,411	102,914
	b Recoverable Costs Allocated to Demand		106,562	106,356	106,150	99,334	104,085	103,879	101,932	101,733	101,534	101,335	101,136	100,938	1,234,973
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		8,630	8,624	8,607	8,063	8,455	8,446	8,283	8,263	8,245	8,227	8,197	8,169	100,209
13	Retail Demand-Related Recoverable Costs (I)		103,560	103,360	103,159	96,535	101,153	100,952	99,060	98,867	98,674	98,480	98,287	98,094	1,200,181
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		112,190	111,984	111,766	104,598	109,607	109,398	107,343	107,130	106,918	106,708	106,484	106,263	1,300,390

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) 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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1601
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		302,205	220,461	92,546	140,131	39,900	(332,713)	193,269	193,269	193,269	193,269	443,269	443,269	2,122,142
	b Clearings to Plant		19,331	53,381	(32,617)	1,047	19,316	36,817	0	0	0	0	0	0	97,275
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	18,033,161	18,052,492	18,105,873	18,073,256	18,074,303	18,093,618	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	
3	Less: Accumulated Depreciation (C)	(657,165)	(727,495)	(797,900)	(868,512)	(938,998)	(1,009,488)	(1,080,053)	(1,150,762)	(1,221,470)	(1,292,179)	(1,362,888)	(1,433,597)	(1,504,305)	
4	CWIP - Non Interest Bearing	1,110,972	1,393,846	1,560,925	1,686,088	1,825,173	1,845,757	1,476,227	1,669,496	1,862,764	2,056,033	2,249,302	2,692,570	3,135,839	
5	Net Investment (Lines 2 + 3 + 4) (A)	18,486,967	18,718,843	18,868,899	18,890,832	18,960,477	18,929,888	18,526,610	18,649,169	18,771,729	18,894,289	19,016,849	19,389,409	19,761,969	
6	Average Net Investment		18,602,905	18,793,871	18,879,865	18,925,654	18,945,182	18,728,249	18,587,890	18,710,449	18,833,009	18,955,569	19,203,129	19,575,689	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		89,313	90,229	90,642	90,862	90,956	89,914	85,895	86,461	87,027	87,594	88,738	90,459	1,068,090
	b Debt Component (Line 6 x Debt Component x 1/12)		21,896	22,120	22,222	22,275	22,298	22,043	21,227	21,367	21,507	21,647	21,930	22,355	262,889
8	Investment Expenses														
	a Depreciation (E)		70,329	70,405	70,613	70,486	70,490	70,565	70,709	70,709	70,709	70,709	70,709	70,709	847,140
	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)		181,537	182,754	183,477	183,623	183,744	182,523	177,831	178,537	179,243	179,950	181,376	183,523	2,178,119
	a Recoverable Costs Allocated to Energy		13,964	14,058	14,114	14,125	14,134	14,040	13,679	13,734	13,788	13,842	13,952	14,117	167,548
	b Recoverable Costs Allocated to Demand		167,573	168,696	169,363	169,498	169,610	168,482	164,151	164,803	165,455	166,107	167,424	169,406	2,010,571
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		13,571	13,680	13,732	13,758	13,777	13,698	13,339	13,386	13,435	13,486	13,570	13,710	163,143
13	Retail Demand-Related Recoverable Costs (I)		162,852	163,944	164,592	164,723	164,832	163,736	159,527	160,161	160,794	161,428	162,708	164,634	1,953,929
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		176,423	177,624	178,324	178,482	178,609	177,434	172,866	173,547	174,229	174,914	176,277	178,344	2,117,072

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E.s 1031, 1158, 1167, 1199, 1250, 1258, 1287, 1958
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		262,898	38,807	550,493	799,891	(47,571)	38,820	0	0	0	80,000	0	0	1,723,338
	b Clearings to Plant		0	0	0	0	2,675,476	38,820	0	0	0	0	80,000	0	2,794,296
	c Retirements		0	344,845	0	0	0	0	282,633	0	0	0	0	0	627,477
	d Cost of Removal		0	25,577	175,031	85,359	16,345	4,677	0	0	0	0	0	0	306,988
	e Salvage		0	0	0	0	(6,267)	0	0	0	0	0	0	0	(6,267)
2	Plant-in-Service/Depreciation Base (B)	120,020,154	120,020,154	119,675,310	119,675,310	119,675,310	122,350,786	122,389,605	122,106,973	122,106,973	122,106,973	122,106,973	122,186,973	122,186,973	
3	Less: Accumulated Depreciation (C)	(31,605,179)	(32,008,514)	(32,041,428)	(32,268,594)	(32,585,432)	(32,965,017)	(33,371,366)	(33,499,887)	(33,910,109)	(34,320,330)	(34,730,552)	(35,140,773)	(35,551,259)	
4	CWIP - Non Interest Bearing	1,070,958	1,333,856	1,372,663	1,923,156	2,723,047	0	0	0	0	0	80,000	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	89,485,933	89,345,496	89,006,545	89,329,872	89,812,925	89,385,769	89,018,240	88,607,085	88,196,864	87,786,643	87,456,421	87,046,200	86,635,714	
6	Average Net Investment		89,415,715	89,176,021	89,168,208	89,571,398	89,599,347	89,202,004	88,812,663	88,401,975	87,991,753	87,621,532	87,251,310	86,840,957	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		429,285	428,134	428,097	430,032	430,166	428,259	410,403	408,506	406,610	404,899	403,188	401,292	5,008,871
	b Debt Component (Line 6 x Debt Component x 1/12)		105,242	104,960	104,951	105,426	105,458	104,991	101,424	100,955	100,487	100,064	99,641	99,172	1,232,771
8	Investment Expenses														
	a Depreciation (E)		393,279	393,279	392,141	392,141	392,141	400,970	401,098	400,166	400,166	400,166	400,166	400,430	4,766,141
	b Amortization (F)		10,056	10,056	10,056	10,056	10,056	10,056	10,056	10,056	10,056	10,056	10,056	10,056	120,672
	c Dismantlement		0	0	0	0	0	0	0	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)		937,862	936,429	935,245	937,655	937,822	944,276	922,982	919,682	917,318	915,184	913,051	910,950	11,128,455
	a Recoverable Costs Allocated to Energy		72,143	72,033	71,942	72,127	72,140	72,637	70,999	70,745	70,563	70,399	70,235	70,073	856,035
	b Recoverable Costs Allocated to Demand		865,719	864,396	863,303	865,528	865,682	871,639	851,983	848,937	846,755	844,786	842,816	840,877	10,272,420
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		70,108	70,095	69,999	70,256	70,318	70,867	69,232	68,956	68,758	68,588	68,310	68,053	833,540
13	Retail Demand-Related Recoverable Costs (I)		841,330	840,044	838,981	841,144	841,293	847,083	827,981	825,021	822,900	820,986	819,072	817,187	9,983,022
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		911,438	910,139	908,980	911,399	911,612	917,950	897,213	893,977	891,658	889,574	887,382	885,240	10,816,562

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) Portions of PEs 1158, 1167, 1199 and 1287 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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.s 1272, 1404, 1628, 4418
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(352,505)	(355,756)	(359,006)	(362,257)	(365,508)	(368,758)	(372,009)	(375,259)	(378,510)	(381,761)	(385,011)	(388,262)	(391,513)	
4	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)	595,420	592,169	588,919	585,668	582,417	579,167	575,916	572,665	569,415	566,164	562,914	559,663	556,412	
6	Average Net Investment		593,795	590,544	587,293	584,043	580,792	577,541	574,291	571,040	567,789	564,539	561,288	558,038	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,851	2,835	2,820	2,804	2,788	2,773	2,654	2,639	2,624	2,609	2,594	2,579	32,568
	b Debt Component (Line 6 x Debt Component x 1/12)		699	695	691	687	684	680	656	652	648	645	641	637	8,015
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	3,094	3,094	37,123
	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)		6,800	6,781	6,761	6,742	6,723	6,703	6,560	6,542	6,523	6,504	6,485	6,467	79,591
	a Recoverable Costs Allocated to Energy		523	522	520	519	517	516	505	503	502	500	499	497	6,122
	b Recoverable Costs Allocated to Demand		6,277	6,259	6,241	6,223	6,205	6,188	6,056	6,038	6,021	6,004	5,986	5,969	73,469
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		508	508	506	505	504	503	492	490	489	487	485	483	5,961
13	Retail Demand-Related Recoverable Costs (I)		6,100	6,083	6,066	6,048	6,031	6,013	5,885	5,868	5,851	5,835	5,818	5,801	71,399
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,609	6,591	6,572	6,553	6,535	6,516	6,377	6,359	6,340	6,322	6,303	6,284	77,360

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(29,525)	(29,732)	(29,940)	(30,147)	(30,355)	(30,562)	(30,770)	(30,977)	(31,185)	(31,392)	(31,599)	(31,807)	(32,014)	
4	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)	33,346	33,138	32,931	32,723	32,516	32,308	32,101	31,893	31,686	31,478	31,271	31,063	30,856	
6	Average Net Investment		33,242	33,034	32,827	32,619	32,412	32,205	31,997	31,790	31,582	31,375	31,167	30,960	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		160	159	158	157	156	155	148	147	146	145	144	143	1,815
	b Debt Component (Line 6 x Debt Component x 1/12)		39	39	39	38	38	38	37	36	36	36	36	35	447
8	Investment Expenses														
	a Depreciation (E)		207	207	207	207	207	207	207	207	207	207	207	207	2,490
	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)		406	405	404	402	401	400	392	391	389	388	387	386	4,752
	a Recoverable Costs Allocated to Energy		31	31	31	31	31	31	30	30	30	30	30	30	366
	b Recoverable Costs Allocated to Demand		375	374	373	372	370	369	362	361	360	358	357	356	4,386
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		30	30	30	30	30	30	29	29	29	29	29	29	356
13	Retail Demand-Related Recoverable Costs (I)		364	363	362	361	360	359	352	350	349	348	347	346	4,263
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		395	394	392	391	390	389	381	380	379	377	376	375	4,619

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1175, 1191, 1305, 1330
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	2,656	0	(2,656)	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)	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	
3	Less: Accumulated Depreciation (C)	(4,715,502)	(4,761,695)	(4,805,231)	(4,851,423)	(4,900,272)	(4,946,464)	(4,992,657)	(5,038,849)	(5,085,042)	(5,131,234)	(5,177,426)	(5,223,619)	(5,269,811)	
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)	9,282,193	9,236,001	9,192,465	9,146,272	9,097,424	9,051,231	9,005,039	8,958,847	8,912,654	8,866,462	8,820,269	8,774,077	8,727,885	
6	Average Net Investment		9,259,097	9,214,233	9,169,369	9,121,848	9,074,328	9,028,135	8,981,943	8,935,750	8,889,558	8,843,366	8,797,173	8,750,981	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		44,453	44,238	44,022	43,794	43,566	43,344	41,506	41,292	41,079	40,865	40,652	40,438	509,248
	b Debt Component (Line 6 x Debt Component x 1/12)		10,898	10,845	10,792	10,736	10,680	10,626	10,257	10,205	10,152	10,099	10,046	9,994	125,331
8	Investment Expenses														
	a Depreciation (E)		46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	554,309
	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)		101,543	101,275	101,007	100,723	100,439	100,163	97,955	97,689	97,423	97,157	96,890	96,624	1,188,888
	a Recoverable Costs Allocated to Energy		7,811	7,790	7,770	7,748	7,726	7,705	7,535	7,515	7,494	7,474	7,453	7,433	91,453
	b Recoverable Costs Allocated to Demand		93,732	93,485	93,237	92,975	92,713	92,458	90,420	90,175	89,929	89,683	89,437	89,192	1,097,435
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		7,591	7,581	7,560	7,547	7,531	7,517	7,348	7,325	7,302	7,281	7,249	7,218	89,049
13	Retail Demand-Related Recoverable Costs (I)		91,092	90,851	90,610	90,356	90,101	89,853	87,873	87,634	87,395	87,157	86,918	86,679	1,066,518
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		98,682	98,432	98,170	97,902	97,632	97,370	95,220	94,959	94,698	94,438	94,167	93,897	1,155,567

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E.s 1218 & 1361
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project
P.E.s 1178, 1227, 1298
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		7,471	(52)	1,066	1,231	1,850	4,081	0	0	250,000	250,000	0	0	515,646
	b Clearings to Plant		210,871	(52)	1,066	1,231	1,850	4,081	0	0	0	0	0	500,000	719,047
	c Retirements		0	0	397,287	0	0	0	0	0	0	0	0	150,000	547,287
	d Cost of Removal		5,618	0	(69)	(8)	21	26	0	0	0	0	0	0	5,588
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	20,023,921	20,234,793	20,234,740	19,838,519	19,839,750	19,841,600	19,845,681	19,845,681	19,845,681	19,845,681	19,845,681	19,845,681	20,195,681	
3	Less: Accumulated Depreciation (C)	(5,272,693)	(5,333,153)	(5,399,928)	(5,069,485)	(5,134,960)	(5,200,410)	(5,265,861)	(5,331,352)	(5,396,843)	(5,462,334)	(5,527,824)	(5,593,315)	(5,508,806)	
4	CWIP - Non Interest Bearing	203,400	0	0	0	0	0	0	0	0	250,000	500,000	500,000	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	14,954,629	14,901,639	14,834,812	14,769,034	14,704,790	14,641,190	14,579,819	14,514,329	14,448,838	14,633,347	14,817,856	14,752,366	14,686,875	
6	Average Net Investment		14,928,134	14,868,226	14,801,923	14,736,912	14,672,990	14,610,505	14,547,074	14,481,583	14,541,092	14,725,602	14,785,111	14,719,620	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		71,670	71,382	71,064	70,752	70,445	70,145	67,222	66,919	67,194	68,047	68,322	68,019	831,183
	b Debt Component (Line 6 x Debt Component x 1/12)		17,570	17,500	17,422	17,345	17,270	17,197	16,613	16,538	16,606	16,817	16,885	16,810	204,572
8	Investment Expenses														
	a Depreciation (E)		66,079	66,775	66,775	65,467	65,471	65,477	65,491	65,491	65,491	65,491	65,491	65,491	788,988
	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)		155,319	155,657	155,261	153,564	153,186.30	152,819	149,326	148,948	149,291	150,354	150,697	150,320	1,824,743
	a Recoverable Costs Allocated to Energy		11,948	11,974	11,943	11,813	11,783.56	11,755	11,487	11,458	11,484	11,566	11,592	11,563	140,365
	b Recoverable Costs Allocated to Demand		143,372	143,683	143,317	141,752	141,402.74	141,064	137,839	137,491	137,807	138,789	139,105	138,757	1,684,378
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		11,611	11,651	11,621	11,506	11,486	11,469	11,201	11,168	11,190	11,268	11,274	11,230	136,675
13	Retail Demand-Related Recoverable Costs (I)		139,333	139,636	139,280	137,758	137,419	137,089	133,956	133,617	133,925	134,879	135,186	134,848	1,636,925
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		150,943	151,287	150,900	149,264	148,905	148,558	145,156	144,785	145,115	146,147	146,461	146,077	1,773,600

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E.s 0433, 1204 & 1299
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	6,100	14,220	15,435	8,090	120,000	470,500	350,000	100,000	0	0	1,084,345
	b Clearings to Plant		0	0	0	0	0	0	0	399,000	0	0	0	0	399,000
	c Retirements		0	0	0	0	0	0	0	385,072	0	0	0	0	385,072
	d Cost of Removal		0	0	0	0	0	0	50,000	50,000	0	0	0	0	100,000
	e Salvage		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	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	
3	Less: Accumulated Depreciation (C)	(2,399,369)	(2,419,674)	(2,439,980)	(2,460,285)	(2,480,590)	(2,500,896)	(2,521,201)	(2,491,507)	(2,076,740)	(2,097,100)	(2,117,459)	(2,137,819)	(2,158,179)	
4	CWIP - Non Interest Bearing	0	0	0	6,100	20,320	35,755	43,845	163,845	235,345	585,345	685,345	685,345	685,345	
5	Net Investment (Lines 2 + 3 + 4) (A)	3,753,771	3,733,466	3,713,160	3,698,956	3,692,870	3,687,999	3,675,784	3,825,478	4,325,673	4,655,313	4,734,953	4,714,594	4,694,234	
6	Average Net Investment		3,743,618	3,723,313	3,706,058	3,695,913	3,690,435	3,681,891	3,750,631	4,075,576	4,490,493	4,695,133	4,724,774	4,704,414	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		17,973	17,876	17,793	17,744	17,718	17,677	17,332	18,833	20,751	21,696	21,833	21,739	228,964
	b Debt Component (Line 6 x Debt Component x 1/12)		4,406	4,382	4,362	4,350	4,344	4,334	4,283	4,654	5,128	5,362	5,396	5,372	56,374
8	Investment Expenses														
	a Depreciation (E)		20,305	20,305	20,305	20,305	20,305	20,305	20,305	20,305	20,360	20,360	20,360	20,360	243,882
	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)		42,685	42,563	42,460	42,400	42,367	42,316	41,920	43,793	46,238	47,418	47,589	47,471	529,219
	a Recoverable Costs Allocated to Energy		3,283	3,274	3,266	3,262	3,259	3,255	3,225	3,369	3,557	3,648	3,661	3,652	40,709
	b Recoverable Costs Allocated to Demand		39,401	39,289	39,194	39,138	39,108	39,061	38,696	40,424	42,682	43,770	43,928	43,820	488,510
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		3,191	3,186	3,178	3,177	3,177	3,176	3,144	3,284	3,466	3,554	3,560	3,546	39,638
13	Retail Demand-Related Recoverable Costs (I)		38,291	38,182	38,090	38,035	38,006	37,960	37,605	39,285	41,479	42,537	42,690	42,585	474,748
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		41,482	41,368	41,268	41,212	41,183	41,136	40,750	42,569	44,945	46,091	46,251	46,131	514,386

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Compliance Program

P.E.s 1034, 1035, 1036, 1037, 1067, 1095, 1168, 1188, 1222, 1233, 1279, 1288, 1362, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1684, 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 1809, 1810, 1824, 1826, 1909, 1911, 1913, 1950
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		1,383,688	2,021,046	3,251,900	2,407,022	407,472	471,902	429,396	510,148	482,148	221,833	506,833	292,333	12,385,720
	b Clearings to Plant		766,276	324,471	193,701	1,791,629	6,055,603	234,002	0	0	0	0	0	0	9,365,681
	c Retirements		910,862	138,741	0	958,222	16,365	1,555,828	1,422,326	0	1,875	0	0	0	5,004,220
	d Cost of Removal		7,631	41,129	364,692	60,056	13,928	21,514	0	0	0	0	0	0	508,950
	e Salvage		0	(3,541)	0	(698,857)	(95,057)	24,059	0	0	0	0	0	0	(773,395)
2	Plant-in-Service/Depreciation Base (B)	1,343,454,328	1,343,309,742	1,343,495,471	1,343,689,172	1,344,522,579	1,350,561,817	1,349,239,991	1,347,817,665	1,347,817,665	1,347,815,790	1,347,815,790	1,347,815,790	1,347,815,790	
3	Less: Accumulated Depreciation (C)	(246,277,835)	(249,236,494)	(252,930,119)	(256,443,064)	(258,604,092)	(262,359,325)	(264,706,458)	(267,180,182)	(271,071,537)	(274,961,018)	(278,852,370)	(282,743,722)	(286,635,074)	
4	CWIP - Non Interest Bearing	6,915,094	7,532,506	9,229,081	12,660,365	13,275,758	7,627,626	7,865,527	8,294,922	8,805,070	9,287,218	9,509,051	10,015,884	10,308,217	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,104,091,587	1,101,605,754	1,099,794,434	1,099,906,473	1,099,194,245	1,095,830,119	1,092,399,059	1,088,932,405	1,085,551,198	1,082,141,990	1,078,472,471	1,075,087,952	1,071,488,933	
6	Average Net Investment		1,102,848,671	1,100,700,094	1,099,850,453	1,099,550,359	1,097,512,182	1,094,114,589	1,090,665,732	1,087,241,802	1,083,846,594	1,080,307,231	1,076,780,212	1,073,288,443	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,294,776	5,284,461	5,280,382	5,278,941	5,269,156	5,252,844	5,039,966	5,024,144	5,008,455	4,992,100	4,975,801	4,959,666	61,660,694
	b Debt Component (Line 6 x Debt Component x 1/12)		1,298,053	1,295,524	1,294,524	1,294,171	1,291,772	1,287,773	1,245,540	1,241,630	1,237,753	1,233,711	1,229,683	1,225,695	15,175,829
8	Investment Expenses														
	a Depreciation (E)		3,848,632	3,848,516	3,849,118	3,849,642	3,852,063	3,871,896	3,867,529	3,862,836	3,862,836	3,862,832	3,862,832	3,862,832	46,301,565
	b Amortization (F)		28,520	28,520	28,520	28,520	28,520	28,520	28,520	28,520	28,520	28,520	28,520	28,520	342,237
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		548,788	548,788	548,788	542,535	547,224	547,224	547,224	547,224	547,224	547,224	547,224	547,224	6,566,693
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		11,018,769	11,005,809	11,001,332	10,993,809	10,988,735	10,988,257	10,728,780	10,704,354	10,684,788	10,664,387	10,644,061	10,623,938	130,047,018
	a Recoverable Costs Allocated to Energy		847,598	846,601	846,256	845,678	845,287	845,251	825,291	823,412	821,907	820,337	818,774	817,226	10,003,617
	b Recoverable Costs Allocated to Demand		10,171,171	10,159,208	10,155,075	10,148,131	10,143,447	10,143,007	9,903,489	9,880,943	9,862,881	9,844,050	9,825,287	9,806,712	120,043,401
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		823,691	823,817	823,397	823,735	823,940	824,657	804,756	802,594	800,886	799,238	796,338	793,666	9,740,715
13	Retail Demand-Related Recoverable Costs (I)		9,884,626	9,873,000	9,868,984	9,862,235	9,857,683	9,857,255	9,624,485	9,602,574	9,585,021	9,566,720	9,548,486	9,530,434	116,661,503
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,708,317	10,696,817	10,692,380	10,685,970	10,681,623	10,681,912	10,429,241	10,405,168	10,385,907	10,365,958	10,344,824	10,324,100	126,402,218

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $787,385,496; Smith $229,742; Daniel $372,892,410, Scherer $182,946,680. Ending Balances: Crist $791,000,404; Smith $229,742; Daniel $373,633,349, Scherer $182,952,295.
(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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.s 0831, 0861 & 1280
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	100,000	0	0	0	200,000	0	300,000
	b Clearings to Plant		0	0	0	0	0	832,922	0	0	0	0	0	0	832,922
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	832,922	832,922	832,922	832,922	832,922	832,922	832,922	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	(2,749)	(5,497)	(8,246)	(10,995)	(13,743)	(16,492)	
4	CWIP - Non Interest Bearing	832,922	832,922	832,922	832,922	832,922	832,922	0	100,000	100,000	100,000	100,000	300,000	300,000	
5	Net Investment (Lines 2 + 3 + 4) (A)	832,922	832,922	832,922	832,922	832,922	832,922	832,922	930,173	927,424	924,676	921,927	1,119,178	1,116,430	
6	Average Net Investment		832,922	832,922	832,922	832,922	832,922	832,922	881,547	928,799	926,050	923,301	1,020,553	1,117,804	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,999	3,999	3,999	3,999	3,999	3,999	4,074	4,292	4,279	4,267	4,716	5,165	50,786
	b Debt Component (Line 6 x Debt Component x 1/12)		980	980	980	980	980	980	1,007	1,061	1,058	1,054	1,165	1,277	12,503
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	2,749	2,749	2,749	2,749	2,749	2,749	16,492
	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)		4,979	4,979	4,979	4,979	4,979	4,979	7,829	8,101	8,085	8,070	8,630	9,191	79,781
	a Recoverable Costs Allocated to Energy		383	383	383	383	383	383	602	623	622	621	664	707	6,137
	b Recoverable Costs Allocated to Demand		4,596	4,596	4,596	4,596	4,596	4,596	7,227	7,478	7,464	7,449	7,966	8,484	73,644
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		372	373	373	373	373	374	587	607	606	605	646	687	5,975
13	Retail Demand-Related Recoverable Costs (I)		4,467	4,467	4,467	4,467	4,467	4,467	7,023	7,267	7,253	7,239	7,742	8,245	71,570
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,839	4,839	4,839	4,840	4,840	4,840	7,610	7,875	7,859	7,844	8,387	8,931	77,545

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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals
P.E.s 0404, 0412, 0424, 0514, 1641, 1997, 4405, 4430, 4440, 6756, 6757, 6759, 6764, 6765, CCR-C, CCR-D, CCR-S
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		1,171,460	1,417,162	1,777,632	1,799,573	3,707,002	3,956,698	4,591,157	3,574,342	5,491,199	8,990,889	4,639,153	5,109,897	46,226,165
	b Clearings to Plant		(46,474)	763,551	(22,923)	142,137	53,422	73	0	0	0	0	0	875,995	1,765,782
	c Retirements		0	0	0	0	0	65,676	0	0	0	0	44,380	0	110,056
	d Cost of Removal		(76,251)	0	0	0	0	0	0	0	0	0	0	0	(76,251)
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	1,750,303	1,703,830	2,467,381	2,444,458	2,586,595	2,640,017	2,574,415	2,574,415	2,574,415	2,574,415	2,574,415	2,530,035	3,406,029	
3	Less: Accumulated Depreciation (C)	(36,344,332)	(36,480,234)	(36,539,805)	(36,600,746)	(36,661,649)	(36,722,984)	(36,718,735)	(36,779,905)	(36,841,075)	(36,902,245)	(36,963,415)	(36,980,205)	(37,041,296)	
4	CWIP - Non Interest Bearing	9,194,671	10,412,605	11,066,216	12,866,770	14,524,207	18,177,787	22,134,412	26,725,569	30,299,911	35,791,110	44,781,999	49,421,152	53,655,054	
5	Net Investment (Lines 2 + 3 + 4) (A)	(25,399,358)	(24,363,800)	(23,006,209)	(21,289,517)	(19,550,847)	(15,905,180)	(12,009,908)	(7,479,921)	(3,966,750)	1,463,280	10,392,998	14,970,981	20,019,788	
6	Average Net Investment		(24,881,579)	(23,685,004)	(22,147,863)	(20,420,182)	(17,728,014)	(13,957,544)	(9,744,915)	(5,723,335)	(1,251,735)	5,928,139	12,681,990	17,495,385	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		(119,456)	(113,712)	(106,332)	(98,037)	(85,112)	(67,010)	(45,031)	(26,448)	(5,784)	27,394	58,603	80,846	(500,079)
	b Debt Component (Line 6 x Debt Component x 1/12)		(29,286)	(27,877)	(26,068)	(24,035)	(20,866)	(16,428)	(11,129)	(6,536)	(1,473)	6,770	14,483	19,980	(122,465)
8	Investment Expenses														
	a Depreciation (E)		4,790	4,711	6,080	6,043	6,474	6,566	6,309	6,309	6,309	6,309	6,309	6,230	72,440
	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		1,185	1,185	1,185	1,233	1,197	1,197	1,197	1,197	1,197	1,197	1,197	1,197	14,361
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		(87,907)	(80,833)	(70,275)	(59,935)	(43,446)	(20,815)	6,207	29,383	55,109	96,531	135,453	163,113	122,585
	a Recoverable Costs Allocated to Energy		(6,762)	(6,218)	(5,406)	(4,610)	(3,342)	(1,601)	477	2,260	4,239	7,425	10,419	12,547	9,430
	b Recoverable Costs Allocated to Demand		(81,145)	(74,615)	(64,869)	(55,325)	(40,104)	(19,214)	5,729	27,123	50,870	89,105	125,034	150,566	113,156
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		(6,571)	(6,051)	(5,260)	(4,491)	(3,258)	(1,562)	466	2,203	4,131	7,234	10,134	12,185	9,161
13	Retail Demand-Related Recoverable Costs (I)		(78,859)	(72,513)	(63,041)	(53,766)	(38,975)	(18,673)	5,568	26,359	49,437	86,595	121,511	146,324	109,968
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		(85,430)	(78,563)	(68,301)	(58,257)	(42,232)	(20,235)	6,034	28,562	53,568	93,829	131,645	158,509	119,129

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $441,896; Smith $462,055; Scherer $69,540; Scholz $672,088; Daniel $104,724. Ending Balances: Crist $441,896; Smith $1,404,285; Scherer $781,943; Scholz $673,181; 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) 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 Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Capital Investments, Depreciation and Taxes
For Project: Steam Electric Effluent Limitations Guidelines
P.E.s 1193 & 1912
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	(9,412)	15,621	66,405	11,270	0	0	0	0	0	0	83,884
	b Clearings to Plant		0	5,571,375	(9,412)	15,621	66,405	11,270	0	0	0	0	0	0	5,655,259
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	5,571,375	5,561,963	5,577,584	5,643,989	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	
3	Less: Accumulated Depreciation (C)	0	0	0	(18,386)	(36,740)	(55,146)	(73,771)	(92,434)	(111,096)	(129,758)	(148,421)	(167,083)	(185,745)	
4	CWIP - Non Interest Bearing	5,571,375	5,571,375	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	5,571,375	5,571,375	5,571,375	5,543,577	5,540,844	5,588,843	5,581,488	5,562,825	5,544,163	5,525,501	5,506,838	5,488,176	5,469,514	
6	Average Net Investment		5,571,375	5,571,375	5,557,476	5,542,211	5,564,844	5,585,165	5,572,157	5,553,494	5,534,832	5,516,169	5,497,507	5,478,845	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		26,748	26,748	26,681	26,608	26,717	26,814	25,749	25,663	25,576	25,490	25,404	25,318	313,517
	b Debt Component (Line 6 x Debt Component x 1/12)		6,558	6,558	6,541	6,523	6,550	6,574	6,363	6,342	6,515	6,299	6,278	6,257	77,357
8	Investment Expenses														
	a Depreciation (E)		0	0	18,386	18,354	18,406	18,625	18,662	18,662	18,662	18,662	18,662	18,662	185,745
	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)		33,306	33,306	51,608	51,486	51,673	52,013	50,775	50,667	50,753	50,452	50,344	50,237	576,620
	a Recoverable Costs Allocated to Energy		2,562	2,562	3,970	3,960	3,975	4,001	3,906	3,897	3,904	3,881	3,873	3,864	44,355
	b Recoverable Costs Allocated to Demand		30,744	30,744	47,638	47,525	47,698	48,012	46,869	46,770	46,849	46,571	46,472	46,373	532,264
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		2,490	2,493	3,863	3,858	3,874	3,904	3,809	3,799	3,804	3,781	3,767	3,753	43,193
13	Retail Demand-Related Recoverable Costs (I)		29,878	29,878	46,296	46,186	46,354	46,660	45,549	45,452	45,529	45,259	45,163	45,066	517,269
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		32,367	32,371	50,159	50,044	50,229	50,563	49,357	49,251	49,334	49,040	48,929	48,819	560,463

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 Current Period Estimated True-up Amount
January 2018 - December 2018
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	Projected July	Projected August	Projected September	Projected October	Projected November	Projected 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		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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 3E.
(E) Line 8 is reported on Schedule 2E.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
January 2018 - December 2018
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	Projected July	Projected August	Projected September	Projected October	Projected November	Projected 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	26,839	23,838	21,614	19,219	17,415	16,886	16,056	15,209	14,371	13,566	11,441	9,566	7,649	
	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	26,839	23,838	21,614	19,219	17,415	16,886	16,056	15,209	14,371	13,566	11,441	9,566	7,649	
4	Average Net Working Capital Balance		25,339	22,726	20,416	18,317	17,150	16,471	15,633	14,790	13,969	12,504	10,504	8,608	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		122	109	98	88	82	79	72	68	65	58	49	40	929
	b Debt Component (Line 4 x Debt Component x 1/12)		30	27	24	22	20	19	18	17	16	14	12	10	229
6	Total Return Component (D)		151	136	122	110	103	98	90	85	81	72	61	50	1,158
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		3,000	2,225	2,395	1,804	529	830	847	838	805	2,125	1,875	1,917	19,189
8	Net Expenses (E)		3,000	2,225	2,395	1,804	529	830	847	838	805	2,125	1,875	1,917	19,189
9	Total System Recoverable Expenses (Lines 6 + 8)		3,152	2,361	2,517	1,913	631	928	937	923	885	2,197	1,935	1,967	20,347
	a Recoverable Costs Allocated to Energy		3,012	2,235	2,404	1,812	537	837	854	844	811	2,131	1,879	1,921	19,278
	b Recoverable Costs Allocated to Demand		140	125	113	101	95	91	83	79	74	67	56	46	1,069
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		2,927	2,175	2,340	1,765	523	817	833	823	790	2,076	1,828	1,866	18,762
13	Retail Demand-Related Recoverable Costs (C)		136	122	109	98	92	88	81	76	72	65	54	45	1,039
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,063	2,297	2,449	1,863	615	905	914	900	862	2,141	1,882	1,910	19,801

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 3E.
(E) Line 8 is reported on Schedule 2E.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
January 2018 - December 2018
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	Projected July	Projected August	Projected September	Projected October	Projected November	Projected 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	36,443	36,443	36,443	36,443	36,443	18,932	24,871	19,357	13,783	9,789	9,789	9,789	9,789	
	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	36,443	36,443	36,443	36,443	36,443	18,932	24,871	19,357	13,783	9,789	9,789	9,789	9,789	
4	Average Net Working Capital Balance		36,443	36,443	36,443	36,443	27,688	21,901	22,114	16,570	11,786	9,789	9,789	9,789	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		175	175	175	175	133	105	102	77	54	45	45	45	1,307
	b Debt Component (Line 4 x Debt Component x 1/12)		43	43	43	43	33	26	25	19	13	11	11	11	321
6	Total Return Component (D)		218	218	218	218	166	131	127	96	68	56	56	56	1,628
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	3,471	7,085	5,514	5,574	3,994	0	0	0	25,638
8	Net Expenses (E)		0	0	0	0	3,471	7,085	5,514	5,574	3,994	0	0	0	25,638
9	Total System Recoverable Expenses (Lines 6 + 8)		218	218	218	218	3,636	7,216	5,641	5,670	4,062	56	56	56	27,266
	a Recoverable Costs Allocated to Energy		17	17	17	17	3,483	7,095	5,523	5,581	4,000	4	4	4	25,763
	b Recoverable Costs Allocated to Demand		201	201	201	201	153	121	118	88	63	52	52	52	1,503
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		16	16	16	16	3,395	6,922	5,386	5,440	3,897	4	4	4	25,119
13	Retail Demand-Related Recoverable Costs (C)		195	195	195	195	148	117	114	86	61	51	51	51	1,460
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		212	212	212	212	3,544	7,040	5,500	5,526	3,958	55	55	55	26,580

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 3E.
(E) Line 8 is reported on Schedule 2E.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
January 2018 - December 2018
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	Projected July	Projected August	Projected September	Projected October	Projected November	Projected 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	51	20	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	6,327,278	6,326,581	6,326,443	6,326,350	6,326,191	6,324,271	6,323,150	6,317,873	6,312,534	6,308,009	6,304,459	6,301,625	6,299,023	
	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	(401)	(388)	(376)	(363)	(351)	(385)	(385)	(366)	(346)	(327)	(307)	(288)	(268)	
3	Total Working Capital Balance	6,326,878	6,326,193	6,326,068	6,325,987	6,325,840	6,323,887	6,322,765.2	6,317,507	6,312,187	6,307,683	6,304,152	6,301,337	6,298,755	
4	Average Net Working Capital Balance		6,326,535	6,326,130	6,326,027	6,325,914	6,324,864	6,323,326	6,320,136	6,314,847	6,309,935	6,305,917	6,302,744	6,300,046	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		30,374	30,372	30,371	30,371	30,366	30,358	29,205	29,181	29,158	29,140	29,125	29,113	357,133
	b Debt Component (Line 4 x Debt Component x 1/12)		7,446	7,446	7,446	7,446	7,444	7,443	7,218	7,212	7,206	7,201	7,198	7,195	87,899
6	Total Return Component (D)		37,820	37,818	37,817	37,816	37,810	37,801	36,423	36,392	36,364	36,341	36,323	36,307	445,032
7	Expenses														
	a Gains		(13)	(13)	(13)	(13)	(17)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(204)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		734	160	118	192	548	1,121	5,278	5,339	4,524	3,550	2,835	2,601	27,000
8	Net Expenses (E)		722	148	105	179	531	1,101	5,258	5,320	4,505	3,531	2,815	2,582	26,796
9	Total System Recoverable Expenses (Lines 6 + 8)		38,542	37,965	37,922	37,995	38,341	38,902	41,681	41,712	40,869	39,872	39,138	38,889	471,828
	a Recoverable Costs Allocated to Energy		3,631	3,057	3,014	3,088	3,439	4,009	8,060	8,119	7,302	6,326	5,609	5,374	61,029
	b Recoverable Costs Allocated to Demand		34,911	34,909	34,908	34,907	34,902	34,893	33,621	33,593	33,567	33,546	33,529	33,514	410,799
10	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		3,529	2,975	2,933	3,008	3,352	3,911	7,859	7,914	7,115	6,164	5,455	5,220	59,435
13	Retail Demand-Related Recoverable Costs (C)		33,927	33,925	33,925	33,924	33,918	33,910	32,674	32,647	32,621	32,600	32,584	32,570	399,226
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		37,456	36,900	36,857	36,932	37,270	37,821	40,533	40,560	39,737	38,764	38,040	37,790	458,661

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 3E.
(E) Line 8 is reported on Schedule 2E.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
January 2018 - December 2018
Return on Working Capital, Amortization Expense
For Project: Regulatory Asset Smith Units 1 & 2
For Retired P.E.s 1413, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1461, 1462, 1468, 1469, 1647, 1620, 1638
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Regulatory Asset Balance 182.2 (B)	21,344,257	21,344,257	21,225,677	21,107,098	20,988,518	20,869,939	20,751,360	20,632,781	20,514,202	20,395,622	20,277,043	20,158,464	20,039,885	
2	Less Amortization (C)	0	(118,580)	(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)	21,344,257	21,225,677	21,107,098	20,988,518	20,869,939	20,751,360	20,632,781	20,514,202	20,395,622	20,277,043	20,158,464	20,039,885	19,921,306	
4	Average Regulatory Asset Balance		21,284,967	21,166,387	21,047,808	20,929,229	20,810,650	20,692,070	20,573,491	20,454,912	20,336,333	20,217,754	20,099,174	19,980,595	
5	Returun on Average Regulatoy Asset Balance														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		102,189	101,620	101,051	100,481	99,912	99,343	95,070	94,522	93,974	93,426	92,878	92,330	1,166,797
	b Debt Component (Line 6 x Debt Component x 1/12)		25,052	24,913	24,773	24,634	24,494	24,355	23,495	23,360	23,224	23,089	22,953	22,818	287,159
6	Amortization Expense														
	a Amortization (E)		118,580	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	118,579	1,422,951
	b Other (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total System Recoverable Expenses (Lines 5 + 6)		245,822	245,112	244,403	243,694	242,985	242,276	237,144	236,461	235,777	235,094	234,411	233,727	2,876,907
	a Recoverable Costs Allocated to Energy		18,909	18,855	18,800	18,746	18,691	18,637	18,242	18,189	18,137	18,084	18,032	17,979	221,301
	b Recoverable Costs Allocated to Demand		226,912	226,257	225,603	224,948	224,294	223,640	218,902	218,272	217,641	217,010	216,379	215,748	2,655,606
8	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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)		18,376	18,347	18,292	18,259	18,219	18,183	17,788	17,729	17,673	17,619	17,537	17,461	215,484
11	Retail Demand-Related Recoverable Costs (H)		220,520	219,883	219,247	218,611	217,975	217,339	212,735	212,122	211,509	210,896	210,283	209,670	2,580,792
12	Total Jurisdictional Recoverable Costs (Lines 10 + 11)		238,896	238,230	237,539	236,870	236,194	235,522	230,523	229,852	229,182	228,515	227,821	227,131	2,796,276

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 9E
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
January 2018 - June 2018

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	743,673	30.7440	4.40	1.3527	1.3527	
2	Short-Term Debt	28,504	1.1784	3.02	0.0356	0.0356	
3	Preferred Stock	94,609	3.9112	6.15	0.2405	0.3221	
4	Common Stock	957,875	39.5993	10.25	4.0589	5.4369	
5	Customer Deposits	24,536	1.0143	2.30	0.0233	0.0233	
6	Deferred Taxes	568,999	23.5229				
7	Investment Tax Credit	721	0.0298	7.61	0.0023	0.0028	
8	Total	2,418,917	100.0000		5.7133	7.1734	0.5978
	ITC Component:						
9	Debt	743,673	41.4036	4.40	1.8218	0.0005	
10	Equity-Preferred	94,609	5.2673	6.15	0.3239	0.0001	
11	-Common	957,875	53.3291	10.25	5.4662	0.0022	
12		1,796,157	100.0000		7.6119	0.0028	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					1.4121	0.1177
14	Total Equity Component (Lines 3, 4, 10, and 11)					5.7613	0.4801
15	Total Revenue Requirement Rate of Return					7.1734	0.5978

Column:

(1) Based on MFR D-1a in Docket No. 160186-EI with the following adjustments in order to reflect specific terms in the Stipulation and Settlement Agreement under the same Docket.
-Reduced the common equity balance and increased the long-term debt balance in order to calculate a 52.5% equity ratio based on jurisdictional investors sources of capital (long-term debt, short-term debt, preference stock and common equity)

(2) Column (1) / Total Column (1)

(3) Based on MFR D-1a in Docket No. 160186-EI with the following adjustments in order to reflect specific terms in the Stipulation and Settlement Agreement under the same Docket.
-Reduced the common equity cost rate to 10.25%.

(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 9E
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
July 2018 - December 2018

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); 25.345% = effective income tax rate
For debt components: Column (4)

(6) Column (5) / 12

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-up Amount
January 2018 - December 2018

For Project: Scherer - Air Quality Compliance and CCR Programs

P.E.s 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 6524, 6756, 6757, 6759, 6764, 6765, CCR-S
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	12-Month Total
1	Investments														
	a Expenditures/Additions		352,056	554,968	653,398	463,971	1,254,690	984,781	1,261,866	783,517	1,123,462	1,256,955	1,391,604	2,082,705	12,163,974
	b Clearings to Plant		3,014	714,393	21,304	20,944	4,596	21	0	0	0	0	0	0	764,273
	c Retirements		0	0	0	0	0	0	0	0	1,875	0	44,380	0	46,255
	d Cost of Removal		(76,251)	0	0	0	0	0	0	0	0	0	0	0	(76,251)
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base	183,016,220	183,019,234	183,733,628	183,754,932	183,775,876	183,780,472	183,780,493	183,780,493	183,780,493	183,778,618	183,778,618	183,734,238	183,734,238	
3	Less: Accumulated Depreciation	(24,375,519)	(24,784,182)	(25,116,600)	(25,450,303)	(25,784,044)	(26,117,823)	(26,451,610)	(26,785,398)	(27,119,185)	(27,451,098)	(27,784,882)	(28,074,286)	(28,407,990)	
4	Working Capital (Emissions)	36,232	33,219	30,986	28,583	26,767	26,230	25,389	24,514	23,649	22,818	20,667	18,770	16,829	
5	CWIP - Non Interest Bearing	6,150,590	6,499,632	6,340,207	6,972,301	7,415,328	8,665,422	9,650,182	10,912,047	11,695,565	12,819,026	14,075,981	15,467,585	17,550,290	
6	Net Investment (Lines 2 + 3 + 4 + 5)	164,827,523	164,767,903	164,988,221	165,305,513	165,433,928	166,354,301	167,004,453	167,931,657	168,380,521	169,169,364	170,090,385	171,146,308	172,893,368	
7	Average Net Investment		164,797,713	164,878,062	165,146,867	165,369,720	165,894,114	166,679,377	167,468,055	168,156,089	168,774,943	169,629,874	170,618,346	172,019,838	
8	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12		791,194	791,580	792,870	793,940	796,458	800,228	773,870	777,049	779,909	783,860	788,427	794,904	9,464,288
	b Debt Component (Line 6 x Debt Component x 1/12)		193,967	194,061	194,378	194,640	195,257	196,182	191,249	192,034	192,741	193,717	194,846	196,447	2,329,519
9	Investment Expenses														
	a Depreciation		329,392	329,397	330,683	330,722	330,759	330,767	330,768	330,768	330,768	330,764	330,764	330,684	3,966,236
	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		24,004	24,004	24,004	27,329	24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	298,024
	e Other		0	0	0	0	0	0	0	0	0	0	0	0	0
10	O&M and Emissions														
	a O&M Expense		132,866	86,072	89,709	121,560	104,399	176,615	165,438	165,456	165,689	149,053	162,091	149,034	1,667,982
	b Emissions Expense		3,169	2,326	2,506	1,952	1,039	1,863	2,287	2,262	2,172	2,454	2,164	2,213	26,406
11	Total System Recoverable Expenses (Lines 8 + 9 + 10)		1,477,611	1,430,460	1,437,170	1,473,163	1,455,767	1,533,510	1,491,466	1,495,424	1,499,134	1,487,703	1,506,148	1,501,137	17,788,694
	a Recoverable Costs Allocated to Energy		236,943	202,602	189,768	221,816	210,636	280,518	265,491	265,777	266,109	250,223	263,401	251,037	2,904,322
	b Recoverable Costs Allocated to Demand		1,240,668	1,227,858	1,247,401	1,251,347	1,245,132	1,252,991	1,225,975	1,229,647	1,233,025	1,237,480	1,242,746	1,250,100	14,884,371
12	Energy Jurisdictional Factor		0.9706307	0.9719222	0.9718210	0.9728861	0.9735769	0.9744672	0.9739494	0.9735495	0.9732564	0.9731115	0.9714319	0.9700069	
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		230,260	197,149	184,642	216,060	205,316	273,684	258,885	259,058	259,303	243,787	256,184	243,800	2,828,129
15	Retail Demand-Related Recoverable Costs		1,205,715	1,193,267	1,212,259	1,216,094	1,210,053	1,217,692	1,191,436	1,195,005	1,198,288	1,202,617	1,207,735	1,214,882	14,465,044
16	Total Jurisdictional Recoverable Costs (Lines 14 + 15)		1,435,975	1,390,416	1,396,901	1,432,154	1,415,369	1,491,376	1,450,322	1,454,063	1,457,591	1,446,404	1,463,919	1,458,682	17,293,173
17	Scherer/Flint Credit(24%)		344,634	333,700	335,256	343,717	339,689	357,930	348,077	348,975	349,822	347,137	351,341	350,084	4,150,362

Schedule 1P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2019 - December 2019

Line No.		Energy ($)	Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period			
	a Projected O & M Activities (Schedule 2P, Lines 7, 8 & 9)	23,101,020	9,564,925	32,665,945
	b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	11,674,807	139,815,780	151,490,587
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	34,775,827	149,380,705	184,156,532
2	True-Up for Estimated Over/(Under) Recovery for the period January 2018 - December 2018 (Schedule 1E, Line 3)	1,793,018	7,643,919	9,436,937
3	Final True-Up for the period January 2017 - December 2017 (Schedule 1A, Line 3)	604,137	2,575,529	3,179,666
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2019 - December 2019 (Line 1c - Line 2 - Line 3)	32,378,672	139,161,257	171,539,929
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	32,401,985	139,261,453	171,663,438

Notes:

Allocation to energy and demand in each period are in proportion to the respective period split of costs indicated on Lines 7 & 8 of Schedules 5E & 7E and 5A & 7A.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 33
PARTY: GULF POWER COMPANY (GULF) (DIRECT)
DESCRIPTION: C. Shane Boyett CSB-3

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019

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 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	0
. 2	Air Emission Fees	2,652	7,867	133,212	2,652	2,652	2,652	2,652	140,152	2,652	2,652	2,652	2,652	305,099	0	305,099
. 3	Title V	22,499	22,499	32,034	23,022	23,022	23,022	23,022	32,034	23,022	23,022	23,026	23,030	293,254	0	293,254
. 4	Asbestos Fees	500	0	0	0	500	0	0	0	0	0	0	0	1,000	1,000	0
. 5	Emission Monitoring	57,923	57,923	66,383	76,007	59,436	59,081	58,957	66,456	59,196	59,071	59,550	59,053	739,036	0	739,036
. 6	General Water Quality	132,136	130,606	165,101	150,256	157,503	196,309	180,209	214,494	185,835	170,908	174,472	156,825	2,014,654	2,014,654	0
. 7	Groundwater Contamination Investigation	228,386	228,386	251,185	231,172	231,172	235,962	235,962	258,370	231,172	231,172	231,172	231,163	2,825,274	2,825,274	0
. 8	State NPDES Administration	11,500	30,500	0	0	0	0	0	0	0	0	0	0	42,000	42,000	0
. 9	Lead & Copper Rule	333	333	333	333	333	333	333	333	333	333	333	337	4,000	4,000	0
. 10	Environmental Auditing/Assessment	0	0	0	0	0	0	0	0	0	7,500	7,500	0	15,000	15,000	0
. 11	General Solid & Hazardous Waste	73,652	72,552	100,655	75,685	76,785	87,285	81,185	98,344	86,285	82,885	81,785	82,902	1,000,000	1,000,000	0
. 12	Above Ground Storage Tanks	5,057	5,057	11,419	5,338	5,569	13,990	5,800	7,353	10,559	5,338	6,031	11,021	92,532	92,532	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	600	600	800	700	800	900	900	1,200	800	700	1,000	1,000	10,000	0	10,000
. 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	64,880	64,879	120,574	98,539	37,494	90,127	95,339	117,560	84,563	67,138	85,986	94,195	1,021,274	0	1,021,274
. 20	Air Quality Compliance Program	2,084,683	1,641,424	2,369,448	1,827,875	1,588,503	1,770,349	1,902,486	2,222,251	1,735,346	1,730,382	1,489,349	1,451,695	21,813,790	0	21,813,790
. 21	MACT ICR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 22	Crist Water Conservation	24,901	22,061	44,630	41,844	28,176	35,332	36,861	43,685	34,076	30,417	53,362	33,197	428,542	428,542	0
. 23	Coal Combustion Residuals	473,374	392,817	311,535	460,294	387,121	300,787	173,342	172,896	139,337	139,429	139,444	139,266	3,229,639	3,229,639	0
. 24	Smith Water Conservation	2,500	2,500	2,500	2,500	2,500	2,500	162,500	2,500	2,500	2,500	2,500	2,500	190,000	190,000	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	514	884	430	504	551	542	501	1,174	984	1,130	7,214	0	7,214
. 27	Seasonal NOx Allowances	0	0	0	0	974	1,816	1,820	2,650	626	0	0	0	7,887	0	7,887
. 28	SO2 Allowances	2,337	1,882	1,874	1,864	3,424	4,664	5,025	5,077	4,200	3,307	1,889	2,219	37,762	0	37,762
. 29	Scherer/Flint Credit - Energy	(30,929)	(73,938)	(90,164)	(41,249)	(38,101)	(35,300)	(35,353)	(35,353)	(35,378)	(31,487)	(34,372)	(31,658)	(513,282)	0	(513,282)
. 30	Scherer/Flint Credit - Demand	(25)	(35)	(56)	(33)	(36)	(32)	(32)	(55)	(33)	(36)	(36)	(30)	(438)	(438)	0
2	Total of O & M Activities	3,156,958	2,607,913	3,521,977	2,957,684	2,568,257	2,790,281	2,931,558	3,350,489	2,565,592	2,526,405	2,326,627	2,260,496	33,564,237	9,842,203	23,722,034
3	Recoverable Costs Allocated to Energy	2,204,644	1,723,136	2,634,675	1,990,294	1,678,633	1,917,816	2,055,399	2,552,570	1,875,528	1,855,959	1,630,065	1,603,315	23,722,034		
4	Recoverable Costs Allocated to Demand	952,314	884,777	887,302	967,389	889,623	872,466	876,159	797,920	690,064	670,446	696,563	657,180	9,842,203		
5	Retail Energy Jurisdictional Factor	0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974			
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)	2,142,055	1,675,896	2,563,801	1,938,904	1,636,294	1,870,695	2,004,926	2,488,748	1,827,788	1,808,586	1,585,930	1,557,399	23,101,020		
8	Jurisdictional Demand Recoverable Costs (B)	925,485	859,851	862,305	940,136	864,561	847,886	851,476	775,441	670,623	651,558	676,939	638,666	9,564,925		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	3,067,540	2,535,747	3,426,106	2,879,039	2,500,855	2,718,581	2,856,401	3,264,188	2,498,411	2,460,144	2,262,868	2,196,065	32,665,945		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Schedule 3P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019

Capital Investment Projects - Recoverable Costs
(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 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
. 1	Air Quality Assurance Testing	31	94	156	219	281	343	1,146	1,142	1,137	1,133	1,128	1,124	7,934	7,324	610
. 2	Crist 5, 6 & 7 Precipitator Projects	318,853	318,213	317,572	316,932	316,291	315,651	315,011	314,370	313,730	313,089	312,449	311,808	3,783,969	3,492,895	291,075
. 3	Crist 7 Flue Gas Conditioning	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	8,641	103,687	95,711	7,976
. 4	Low NOx Burners, Crist 6 & 7	148,964	148,698	148,432	148,165	147,899	147,632	147,366	147,099	146,833	146,567	146,300	146,034	1,769,988	1,633,835	136,153
. 5	CEMS - Plants Crist & Daniel	45,428	45,399	45,370	45,629	45,518	46,382	46,295	46,209	46,122	46,036	45,949	45,863	550,201	507,877	42,323
. 6	Substation Contamination Remediation	28,168	32,163	33,551	34,938	36,326	37,713	42,262	42,190	42,117	42,045	41,973	41,900	455,346	420,320	35,027
. 7	Raw Water Well Flowmeters - Plants Crist & Smith	1,099	1,096	1,093	1,090	1,087	1,084	1,082	1,079	1,076	1,073	1,070	1,067	12,997	11,997	1,000
. 8	Crist Cooling Tower Cell	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	36,786	33,956	2,830
. 9	Crist Dechlorination System	2,042	2,035	2,027	2,020	2,013	2,006	1,998	1,991	1,984	1,977	1,969	1,962	24,024	22,176	1,848
. 10	Crist Diesel Fuel Oil Remediation	331	330	328	327	326	324	323	322	320	319	318	316	3,884	3,585	299
. 11	Crist Bulk Tanker Unloading Secondary Containment	434	432	430	428	426	425	423	421	419	417	415	413	5,083	4,692	391
. 12	Crist IWW Sampling System	253	252	251	249	248	247	246	245	244	243	242	240	2,960	2,732	228
. 13	Sodium Injection System	1,830	1,825	1,819	1,814	1,808	1,803	1,798	1,792	1,787	1,781	1,776	1,771	21,603	19,942	1,662
. 14	Smith Stormwater Collection System	14,825	14,763	14,700	14,638	14,576	14,514	14,452	14,390	14,328	14,266	14,203	14,141	173,796	160,427	13,369
. 15	Smith Waste Water Treatment Facility	4,917	5,932	5,918	5,905	5,892	5,879	5,865	5,852	5,839	5,825	5,812	5,799	69,434	64,093	5,341
. 16	Daniel Ash Management Project	109,297	109,082	108,866	108,651	108,436	108,220	108,005	107,789	107,574	107,359	107,143	106,928	1,297,351	1,197,554	99,796
. 17	Smith Water Conservation	184,629	185,560	187,577	191,657	197,958	205,015	212,827	221,154	229,753	238,351	245,952	252,070	2,552,502	2,356,156	196,346
. 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	908,533	906,168	903,803	901,437	899,072	896,707	894,341	891,976	889,611	887,245	885,168	883,379	10,747,440	9,920,714	826,726
. 20	SPCC Compliance	6,448	6,429	6,410	6,392	6,373	6,354	6,335	6,317	6,298	6,279	6,261	6,242	76,138	70,281	5,857
. 21	Crist Common FTIR Monitor	385	383	382	381	380	379	378	376	375	374	373	372	4,537	4,188	349
. 22	Precipitator Upgrades for CAM Compliance	96,358	96,092	95,826	95,559	95,293	95,027	94,761	94,495	94,228	93,962	93,696	93,430	1,138,727	1,051,133	87,594
. 23	Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 24	Crist Water Conservation	151,161	150,869	150,532	150,196	149,860	149,524	149,188	148,852	148,516	148,180	147,844	147,508	1,792,231	1,654,367	137,864
. 25	Plant NPDES Permit Compliance Projects	47,354	47,237	47,119	47,002	46,885	46,767	46,650	46,533	46,415	46,298	46,181	46,063	560,503	517,387	43,116
. 26	Air Quality Compliance Program	10,602,004	10,594,935	10,573,165	10,551,395	10,530,635	10,511,317	10,493,841	10,477,429	10,462,935	10,447,626	10,431,685	10,417,484	126,094,451	116,394,877	9,699,573
. 27	General Water Quality	9,175	9,159	9,143	9,127	9,111	9,096	9,080	9,064	9,048	9,032	9,016	9,000	109,051	100,662	8,389
. 28	Coal Combustion Residuals	197,926	234,983	275,652	313,006	360,989	386,536	407,111	447,957	486,919	500,782	513,777	526,840	4,652,479	4,294,596	357,883
. 29	Steam Electric Effluent Limitations Guidelines	50,701	51,233	51,261	51,289	51,316	51,344	51,372	51,400	51,427	51,455	51,483	51,511	615,793	568,424	47,369
30	316(b) Cooling Water Intake Structure Regulation	0	288	864	1,153	1,153	1,297	2,593	6,483	9,581	10,301	11,022	11,454	56,189	51,867	4,322
. 31	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
. 32	Annual NOx Allowances	44	44	43	39	35	32	29	26	23	18	12	6	350	323	27
. 33	Seasonal NOx Allowances	56	56	56	56	54	46	35	22	13	11	11	11	428	395	33
. 34	SO2 Allowances	36,293	36,281	36,270	36,259	36,244	36,221	36,193	36,164	36,137	36,115	36,100	36,089	434,365	400,953	33,413
. 35	Regulatory Asset Smith Units 1 & 2	233,044	232,361	231,677	230,994	230,311	229,627	228,944	228,260	227,577	226,894	226,210	225,527	2,751,425	2,539,777	211,648
. 36	Scherer/Flint Credit - Energy	(25,069)	(25,198)	(25,318)	(25,438)	(25,919)	(26,038)	(26,084)	(26,513)	(26,486)	(26,459)	(26,432)	(26,405)	(311,360)	0	(311,360)
. 37	Scherer/Flint Credit - Demand	(300,832)	(302,381)	(303,818)	(305,253)	(311,033)	(312,453)	(313,012)	(318,160)	(317,829)	(317,508)	(317,186)	(316,855)	(3,736,320)	(3,736,320)	0
2	Total Investment Projects - Recoverable Costs	12,886,388	12,916,516	12,932,867	12,947,964	12,971,550	12,980,726	12,992,559	13,018,431	13,049,757	13,052,792	13,053,625	13,054,799	155,857,972	143,868,898	11,989,075
3	Recoverable Costs Allocated to Energy	991,261	993,578	994,836	995,997	997,812	998,517	999,428	1,001,418	1,003,827	1,004,061	1,004,125	1,004,215	11,989,075		
4	Recoverable Costs Allocated to Demand	11,895,127	11,922,938	11,938,031	11,951,966	11,973,738	11,982,209	11,993,131	12,017,013	12,045,930	12,048,731	12,049,500	12,050,583	143,868,898		
5	Retail Energy Jurisdictional Factor	0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974			
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)	963,119	966,339.39	968,074	970,280	972,644	973,984	974,885	976,379	978,276	978,433	976,938	975,456	11,674,807		
8	Jurisdictional Demand Recoverable Costs (C)	11,560,014	11,587,041	11,601,709	11,615,252	11,636,410	11,644,642	11,655,257	11,678,466	11,706,568	11,709,291	11,710,038	11,711,091	139,815,780		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	12,523,133	12,553,380	12,569,784	12,585,532	12,609,054	12,618,626	12,630,142	12,654,845	12,684,844	12,687,723	12,686,976	12,686,547	151,490,587		

Notes:
(A) Pages 1-30 of Schedule 4P, Line 9, Pages 31-34 of Schedule 4P, Line 6, Page 35, Line 7, Schedule 9P, 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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		10,833	10,833	10,833	10,833	10,833	10,835	0	0	0	0	0	0	65,000
	b Clearings to Plant		0	0	0	0	0	65,000	0	0	0	0	0	0	65,000
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	65,000	65,000	65,000	65,000	65,000	65,000	65,000	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	(774)	(1,548)	(2,321)	(3,095)	(3,869)	(4,643)	
4	CWIP - Non Interest Bearing	0	10,833	21,666	32,499	43,332	54,165	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	10,833	21,666	32,499	43,332	54,165	65,000	64,226	63,452	62,679	61,905	61,131	60,357	
6	Average Net Investment		5,417	16,250	27,083	37,916	48,749	59,583	64,613	63,839	63,065	62,292	61,518	60,744	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		25	75	125	175	225	275	299	295	291	288	284	281	2,639
	b Debt Component (Line 6 x Debt Component x 1/12)		6	19	31	43	56	68	74	73	72	71	70	69	652
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	774	774	774	774	774	774	4,643
	c Dismantlement		0	0	0	0	0	0	0	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)		31	94	156	219	281	343	1,146	1,142	1,137	1,133	1,128	1,124	7,934
	a Recoverable Costs Allocated to Energy		2	7	12	17	22	26	88	88	87	87	87	86	610
	b Recoverable Costs Allocated to Demand		29	86	144	202	259	317	1,058	1,054	1,050	1,046	1,042	1,037	7,324
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	7	12	16	21	26	86	86	85	85	84	84	594
13	Retail Demand-Related Recoverable Costs (I)		28	84	140	196	252	308	1,028	1,024	1,020	1,016	1,012	1,008	7,117
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		30	91	152	212	273	334	1,114	1,110	1,105	1,101	1,097	1,092	7,712

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	33,677,323	
3	Less: Accumulated Depreciation (C)	2,421,657	2,310,521	2,199,386	2,088,251	1,977,116	1,865,981	1,754,845	1,643,710	1,532,575	1,421,440	1,310,305	1,199,170	1,088,034	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	36,098,980	35,987,844	35,876,709	35,765,574	35,654,439	35,543,304	35,432,169	35,321,033	35,209,898	35,098,763	34,987,628	34,876,493	34,765,358	
6	Average Net Investment		36,043,412	35,932,277	35,821,142	35,710,007	35,598,871	35,487,736	35,376,601	35,265,466	35,154,331	35,043,196	34,932,060	34,820,925	
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	163,989	163,475	162,962	162,448	161,935	161,421	160,907	1,964,785
	b Debt Component (Line 6 x Debt Component x 1/12)		41,162	41,035	40,908	40,781	40,654	40,527	40,400	40,273	40,146	40,019	39,892	39,765	485,562
8	Investment Expenses														
	a Depreciation (E)		111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	111,135	1,333,622
	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 (Lines 7 + 8)		318,853	318,213	317,572	316,932	316,291	315,651	315,011	314,370	313,730	313,089	312,449	311,808	3,783,969
	a Recoverable Costs Allocated to Energy		24,527	24,478	24,429	24,379	24,330	24,281	24,232	24,182	24,133	24,084	24,035	23,985	291,075
	b Recoverable Costs Allocated to Demand		294,326	293,735	293,144	292,553	291,961	291,370	290,779	290,188	289,597	289,005	288,414	287,823	3,492,895
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		23,831	23,807	23,772	23,750	23,716	23,684	23,637	23,578	23,519	23,469	23,384	23,298	283,444
13	Retail Demand-Related Recoverable Costs (I)		286,034	285,460	284,885	284,311	283,736	283,162	282,587	282,012	281,438	280,863	280,289	279,714	3,394,492
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		309,865	309,267	308,657	308,061	307,453	306,846	306,224	305,590	304,957	304,332	303,673	303,013	3,677,936

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	6,928	6,928	6,928	6,928	6,928	6,928	83,140
	b Debt Component (Line 6 x Debt Component x 1/12)		1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	20,547
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	8,641	8,641	8,641	8,641	8,641	8,641	103,687
	a Recoverable Costs Allocated to Energy		665	665	665	665	665	665	665	665	665	665	665	665	7,976
	b Recoverable Costs Allocated to Demand		7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	7,976	95,711
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		646	646	647	647	648	648	648	648	648	648	647	646	7,767
13	Retail Demand-Related Recoverable Costs (I)		7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	7,751	93,015
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,397	8,398	8,398	8,399	8,399	8,400	8,400	8,399	8,399	8,399	8,398	8,397	100,782

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	13,634,258	
3	Less: Accumulated Depreciation (C)	4,215,387	4,169,157	4,122,927	4,076,697	4,030,467	3,984,236	3,938,006	3,891,776	3,845,546	3,799,316	3,753,086	3,706,856	3,660,626	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	17,849,645	17,803,415	17,757,185	17,710,955	17,664,725	17,618,495	17,572,265	17,526,035	17,479,805	17,433,575	17,387,345	17,341,115	17,294,884	
6	Average Net Investment		17,826,530	17,780,300	17,734,070	17,687,840	17,641,610	17,595,380	17,549,150	17,502,920	17,456,690	17,410,460	17,364,230	17,317,999	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		82,376	82,163	81,949	81,736	81,522	81,308	81,095	80,881	80,667	80,454	80,240	80,026	974,417
	b Debt Component (Line 6 x Debt Component x 1/12)		20,358	20,305	20,252	20,200	20,147	20,094	20,041	19,988	19,936	19,883	19,830	19,777	240,810
8	Investment Expenses														
	a Depreciation (E)		44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	44,519	534,224
	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)		148,964	148,698	148,432	148,165	147,899	147,632	147,366	147,099	146,833	146,567	146,300	146,034	1,769,988
	a Recoverable Costs Allocated to Energy		11,459	11,438	11,418	11,397	11,377	11,356	11,336	11,315	11,295	11,274	11,254	11,233	136,153
	b Recoverable Costs Allocated to Demand		137,506	137,260	137,014	136,768	136,522	136,276	136,030	135,784	135,538	135,292	135,046	134,800	1,633,835
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		11,133	11,125	11,111	11,103	11,090	11,077	11,057	11,032	11,007	10,987	10,949	10,912	132,584
13	Retail Demand-Related Recoverable Costs (I)		133,632	133,393	133,154	132,915	132,676	132,437	132,198	131,959	131,720	131,481	131,242	131,003	1,587,807
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		144,765	144,517	144,264	144,018	143,766	143,514	143,255	142,991	142,727	142,467	142,191	141,914	1,720,390

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) 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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist & Daniel
P.E.s 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1312, 1316, 1323, 1324, 1325, 1357, 1358, 1364, 1558, 1570, 1592, 1658, 1829, 1830
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	100,000	100,000	0	0	0	0	0	0	0	200,000
	b Clearings to Plant		0	0	0	0	200,000	0	0	0	0	0	0	0	200,000
	c Retirements		0	0	0	200,000	0	0	0	0	0	0	0	0	200,000
	d Cost of Removal		0	20,000	0	20,000	0	0	0	0	0	0	0	0	40,000
	e Salvage		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	4,490,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	4,690,600	
3	Less: Accumulated Depreciation (C)	447,258	432,247	437,236	422,224	627,213	612,861	597,850	582,838	567,827	552,815	537,804	522,792	507,781	
4	CWIP - Non Interest Bearing	0	0	0	0	100,000	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	5,137,858	5,122,847	5,127,835	5,112,824	5,217,813	5,303,461	5,288,450	5,273,438	5,258,427	5,243,415	5,228,404	5,213,392	5,198,381	
6	Average Net Investment		5,130,353	5,125,341	5,120,330	5,165,318	5,260,637	5,295,955	5,280,944	5,265,932	5,250,921	5,235,909	5,220,898	5,205,886	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		23,707	23,684	23,661	23,869	24,309	24,473	24,403	24,334	24,265	24,195	24,126	24,056	289,082
	b Debt Component (Line 6 x Debt Component x 1/12)		5,859	5,853	5,847	5,899	6,008	6,048	6,031	6,014	5,997	5,979	5,962	5,945	71,442
8	Investment Expenses														
	a Depreciation (E)		15,011	15,011	15,011	15,011	14,351	15,011	15,011	15,011	15,011	15,011	15,011	15,011	179,478
	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		850	850	850	850	850	850	850	850	850	850	850	850	10,199
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		45,428	45,399	45,370	45,629	45,518	46,382	46,295	46,209	46,122	46,036	45,949	45,863	550,201
	a Recoverable Costs Allocated to Energy		3,494	3,492	3,490	3,510	3,501	3,568	3,561	3,555	3,548	3,541	3,535	3,528	42,323
	b Recoverable Costs Allocated to Demand		41,933	41,906	41,880	42,119	42,017	42,814	42,734	42,654	42,575	42,495	42,415	42,335	507,877
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		3,395	3,396	3,396	3,419	3,413	3,480	3,474	3,466	3,458	3,451	3,439	3,427	41,214
13	Retail Demand-Related Recoverable Costs (I)		40,752	40,726	40,700	40,933	40,833	41,608	41,530	41,453	41,375	41,298	41,220	41,142	493,569
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		44,147	44,122	44,096	44,352	44,246	45,088	45,004	44,918	44,833	44,748	44,659	44,569	534,783

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist $4,106,227; Daniel $584,373. Ending Balances: Crist $4,106,227; Daniel $584,373.
(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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Substation Contamination Remediation
P.E.s 1007, 2859, 3400, 3412, 3463, 3477
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		249,416	249,416	249,416	249,416	249,416	249,416	0	0	0	0	0	0	1,496,496
	b Clearings to Plant		1,000,000	0	0	0	0	1,496,496	0	0	0	0	0	0	2,496,496
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	2,483,333	3,483,333	3,483,333	3,483,333	3,483,333	3,483,333	4,979,829	4,979,829	4,979,829	4,979,829	4,979,829	4,979,829	4,979,829	
3	Less: Accumulated Depreciation (C)	(598,002)	(604,051)	(612,701)	(621,351)	(630,000)	(638,650)	(647,300)	(659,840)	(672,381)	(684,921)	(697,462)	(710,002)	(722,543)	
4	CWIP - Non Interest Bearing	1,831,000	1,080,416	1,329,832	1,579,248	1,828,664	2,078,080	831,000	831,000	831,000	831,000	831,000	831,000	831,000	
5	Net Investment (Lines 2 + 3 + 4) (A)	3,716,332	3,959,698	4,200,465	4,441,231	4,681,997	4,922,764	5,163,530	5,150,989	5,138,449	5,125,908	5,113,368	5,100,827	5,088,287	
6	Average Net Investment		3,838,015	4,080,081	4,320,848	4,561,614	4,802,380	5,043,147	5,157,260	5,144,719	5,132,179	5,119,638	5,107,097	5,094,557	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		17,735	18,854	19,967	21,079	22,192	23,304	23,832	23,774	23,716	23,658	23,600	23,542	265,252
	b Debt Component (Line 6 x Debt Component x 1/12)		4,383	4,659	4,934	5,209	5,484	5,759	5,890	5,875	5,861	5,847	5,832	5,818	65,553
8	Investment Expenses														
	a Depreciation (E)		6,050	8,650	8,650	8,650	8,650	8,650	12,541	12,541	12,541	12,541	12,541	12,541	124,541
	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)		28,168	32,163	33,551	34,938	36,326	37,713	42,262	42,190	42,117	42,045	41,973	41,900	455,346
	a Recoverable Costs Allocated to Energy		2,167	2,474	2,581	2,688	2,794	2,901	3,251	3,245	3,240	3,234	3,229	3,223	35,027
	b Recoverable Costs Allocated to Demand		26,001	29,689	30,970	32,251	33,532	34,812	39,011	38,944	38,878	38,811	38,744	38,677	420,320
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		2,105	2,406	2,511	2,618	2,724	2,830	3,171	3,164	3,157	3,152	3,141	3,131	34,111
13	Retail Demand-Related Recoverable Costs (I)		25,269	28,853	30,097	31,342	32,587	33,832	37,912	37,847	37,782	37,717	37,653	37,588	408,478
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		27,374	31,259	32,609	33,960	35,311	36,661	41,083	41,011	40,940	40,869	40,794	40,719	442,589

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E.s 1155 & 1606
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(50,354)	(50,849)	
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) (A)	105,038	104,544	104,049	103,554	103,059	102,564	102,069	101,575	101,080	100,585	100,090	99,595	99,100	
6	Average Net Investment		104,791	104,296	103,801	103,306	102,812	102,317	101,822	101,327	100,832	100,337	99,843	99,348	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		484	482	480	477	475	473	471	468	466	464	461	459	5,660
	b Debt Component (Line 6 x Debt Component x 1/12)		120	119	119	118	117	117	116	116	115	115	114	113	1,399
8	Investment Expenses														
	a Depreciation (E)		495	495	495	495	495	495	495	495	495	495	495	495	5,938
	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	1,082	1,079	1,076	1,073	1,070	1,067	12,997
	a Recoverable Costs Allocated to Energy		85	84	84	84	84	83	83	83	83	83	82	82	1,000
	b Recoverable Costs Allocated to Demand		1,014	1,012	1,009	1,006	1,004	1,001	998	996	993	991	988	985	11,997
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	81	81	81	81	80	80	80	974
13	Retail Demand-Related Recoverable Costs (I)		986	983	981	978	975	973	970	968	965	963	960	958	11,659
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,068	1,065	1,062	1,060	1,057	1,054	1,051	1,049	1,046	1,043	1,040	1,037	12,632

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	2,458	2,458	2,458	2,458	2,458	2,458	29,496
	b Debt Component (Line 6 x Debt Component x 1/12)		607	607	607	607	607	607	607	607	607	607	607	607	7,290
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	3,065	3,065	3,065	3,065	3,065	3,065	36,786
	a Recoverable Costs Allocated to Energy		236	236	236	236	236	236	236	236	236	236	236	236	2,830
	b Recoverable Costs Allocated to Demand		2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	2,830	33,956
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		229	229	229	230	230	230	230	230	230	230	229	229	2,756
13	Retail Demand-Related Recoverable Costs (I)		2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	33,000
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,979	2,979	2,979	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,979	2,979	35,755

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Dechlorination System
P.E.s 1180 & 1248
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(257,587)	(258,844)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	136,929	135,673	134,417	133,160	131,904	130,648	129,391	128,135	126,879	125,622	124,366	123,110	121,854	
6	Average Net Investment		136,301	135,045	133,788	132,532	131,276	130,019	128,763	127,507	126,251	124,994	123,738	122,482	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		630	624	618	612	607	601	595	589	583	578	572	566	7,175
	b Debt Component (Line 6 x Debt Component x 1/12)		156	154	153	151	150	148	147	146	144	143	141	140	1,773
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	1,256	1,256	15,076
	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	1,998	1,991	1,984	1,977	1,969	1,962	24,024
	a Recoverable Costs Allocated to Energy		157	157	156	155	155	154	154	153	153	152	151	151	1,848
	b Recoverable Costs Allocated to Demand		1,885	1,878	1,871	1,865	1,858	1,851	1,845	1,838	1,831	1,825	1,818	1,811	22,176
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	152	152	151	151	150	150	149	149	148	147	147	1,800
13	Retail Demand-Related Recoverable Costs (I)		1,832	1,825	1,819	1,812	1,806	1,799	1,793	1,786	1,780	1,773	1,767	1,760	21,551
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,984	1,977	1,970	1,964	1,957	1,950	1,943	1,936	1,928	1,921	1,914	1,907	23,351

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(50,860)	(51,088)	(51,315)	(51,543)	(51,770)	(51,997)	(52,225)	(52,452)	(52,680)	(52,907)	(53,135)	(53,362)	(53,590)	
4	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	16,698	16,471	16,243	16,016	15,788	15,561	15,333	
6	Average Net Investment		17,949	17,722	17,494	17,267	17,039	16,812	16,584	16,357	16,130	15,902	15,675	15,447	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		83	82	81	80	79	78	77	76	75	73	72	71	926
	b Debt Component (Line 6 x Debt Component x 1/12)		20	20	20	20	19	19	19	19	18	18	18	18	229
8	Investment Expenses														
	a Depreciation (E)		227	227	227	227	227	227	227	227	227	227	227	227	2,729
	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	324	323	322	320	319	318	316	3,884
	a Recoverable Costs Allocated to Energy		25	25	25	25	25	25	25	25	25	25	24	24	299
	b Recoverable Costs Allocated to Demand		305	304	303	302	301	299	298	297	296	295	293	292	3,585
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	24	24	24	24	24	24	24	291
13	Retail Demand-Related Recoverable Costs (I)		297	296	294	293	292	291	290	289	287	286	285	284	3,484
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		322	320	319	318	317	315	314	313	311	310	309	308	3,775

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unloading Secondary Containment
P.E. 1271
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(87,793)	(88,128)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	17,387	17,052	16,717	16,382	16,047	15,712	15,377	15,042	14,707	14,372	14,037	13,702	13,367	
6	Average Net Investment		17,219	16,884	16,549	16,214	15,879	15,544	15,210	14,875	14,540	14,205	13,870	13,535	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		80	78	76	75	73	72	70	69	67	66	64	63	853
	b Debt Component (Line 6 x Debt Component x 1/12)		20	19	19	19	18	18	17	17	17	16	16	15	211
8	Investment Expenses														
	a Depreciation (E)		335	335	335	335	335	335	335	335	335	335	335	335	4,019
	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		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	419	417	415	413	5,083
	a Recoverable Costs Allocated to Energy		33	33	33	33	33	33	33	32	32	32	32	32	391
	b Recoverable Costs Allocated to Demand		401	399	397	395	394	392	390	388	387	385	383	381	4,692
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		32	32	32	32	32	32	32	32	31	31	31	31	381
13	Retail Demand-Related Recoverable Costs (I)		389	388	386	384	383	381	379	377	376	374	372	370	4,559
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		422	420	418	416	415	413	411	409	407	405	403	401	4,940

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(51,823)	(52,019)	
4	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	7,720	7,524	
6	Average Net Investment		9,783	9,587	9,390	9,194	8,997	8,801	8,604	8,408	8,211	8,015	7,818	7,622	
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	483
	b Debt Component (Line 6 x Debt Component x 1/12)		11	11	11	10	10	10	10	10	9	9	9	9	119
8	Investment Expenses														
	a Depreciation (E)		196	196	196	196	196	196	196	196	196	196	196	196	2,358
	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	246	245	244	243	242	240	2,960
	a Recoverable Costs Allocated to Energy		19	19	19	19	19	19	19	19	19	19	19	18	228
	b Recoverable Costs Allocated to Demand		233	232	231	230	229	228	227	226	225	224	223	222	2,732
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	217	216	2,655
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		246	245	244	242	241	240	239	238	237	236	235	234	2,877

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(139,912)	(140,852)	
4	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	144,709	143,770	
6	Average Net Investment		154,572	153,632	152,693	151,754	150,815	149,875	148,936	147,997	147,058	146,118	145,179	144,240	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		714	710	706	701	697	693	688	684	680	675	671	667	8,285
	b Debt Component (Line 6 x Debt Component x 1/12)		177	175	174	173	172	171	170	169	168	167	166	165	2,047
8	Investment Expenses														
	a Depreciation (E)		939	939	939	939	939	939	939	939	939	939	939	939	11,271
	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	1,798	1,792	1,787	1,781	1,776	1,771	21,603
	a Recoverable Costs Allocated to Energy		141	140	140	140	139	139	138	138	137	137	137	136	1,662
	b Recoverable Costs Allocated to Demand		1,689	1,684	1,679	1,674	1,669	1,664	1,659	1,654	1,649	1,644	1,639	1,634	19,942
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	135	135	134	134	134	133	132	1,618
13	Retail Demand-Related Recoverable Costs (I)		1,642	1,637	1,632	1,627	1,622	1,617	1,613	1,608	1,603	1,598	1,593	1,588	19,380
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,778	1,773	1,768	1,763	1,758	1,753	1,747	1,742	1,737	1,732	1,726	1,721	20,998

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(2,175,922)	(2,186,703)	
4	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	588,457	577,676	
6	Average Net Investment		701,658	690,877	680,096	669,315	658,534	647,753	636,972	626,190	615,409	604,628	593,847	583,066	
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	2,943	2,894	2,844	2,794	2,744	2,694	35,620
	b Debt Component (Line 6 x Debt Component x 1/12)		801	789	777	764	752	740	727	715	703	690	678	666	8,803
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	10,781	10,781	129,373
	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	14,452	14,390	14,328	14,266	14,203	14,141	173,796
	a Recoverable Costs Allocated to Energy		1,140	1,136	1,131	1,126	1,121	1,116	1,112	1,107	1,102	1,097	1,093	1,088	13,369
	b Recoverable Costs Allocated to Demand		13,684	13,627	13,570	13,512	13,455	13,398	13,340	13,283	13,226	13,168	13,111	13,054	160,427
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		1,108	1,104	1,100	1,097	1,093	1,089	1,084	1,079	1,074	1,069	1,063	1,057	13,018
13	Retail Demand-Related Recoverable Costs (I)		13,299	13,243	13,187	13,132	13,076	13,020	12,964	12,909	12,853	12,797	12,741	12,686	155,908
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		14,407	14,348	14,288	14,229	14,169	14,109	14,049	13,988	13,927	13,867	13,804	13,742	168,926

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E.s 1466 & 1643
(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	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		262,903	0	0	0	0	0	0	0	0	0	0	0	262,903
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	328,962	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	591,865	
3	Less: Accumulated Depreciation (C)	39,323	38,040	35,731	33,423	31,115	28,807	26,498	24,190	21,882	19,573	17,265	14,957	12,649	
4	CWIP - Non Interest Bearing	262,903	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	631,188	629,905	627,596	625,288	622,980	620,672	618,363	616,055	613,747	611,438	609,130	606,822	604,514	
6	Average Net Investment		630,546	628,750	626,442	624,134	621,826	619,517	617,209	614,901	612,593	610,284	607,976	605,668	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,914	2,905	2,895	2,884	2,873	2,863	2,852	2,841	2,831	2,820	2,809	2,799	34,287
	b Debt Component (Line 6 x Debt Component x 1/12)		720	718	715	713	710	707	705	702	700	697	694	692	8,473
8	Investment Expenses														
	a Depreciation (E)		1,283	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	26,674
	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)		4,917	5,932	5,918	5,905	5,892	5,879	5,865	5,852	5,839	5,825	5,812	5,799	69,434
	a Recoverable Costs Allocated to Energy		378	456	455	454	453	452	451	450	449	448	447	446	5,341
	b Recoverable Costs Allocated to Demand		4,539	5,475	5,463	5,451	5,439	5,426	5,414	5,402	5,390	5,377	5,365	5,353	64,093
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		367	444	443	443	442	441	440	439	438	437	435	433	5,201
13	Retail Demand-Related Recoverable Costs (I)		4,411	5,321	5,309	5,297	5,285	5,273	5,262	5,250	5,238	5,226	5,214	5,202	62,288
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,778	5,765	5,752	5,740	5,727	5,715	5,702	5,689	5,675	5,662	5,649	5,635	67,489

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E.s 1501, 1535, 1555, 1819
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	14,950,124	
3	Less: Accumulated Depreciation (C)	(6,384,689)	(6,422,064)	(6,459,439)	(6,496,815)	(6,534,190)	(6,571,565)	(6,608,941)	(6,646,316)	(6,683,691)	(6,721,066)	(6,758,442)	(6,795,817)	(6,833,192)	
4	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	8,341,183	8,303,808	8,266,433	8,229,058	8,191,682	8,154,307	8,116,932	
6	Average Net Investment		8,546,748	8,509,372	8,471,997	8,434,622	8,397,246	8,359,871	8,322,496	8,285,120	8,247,745	8,210,370	8,172,995	8,135,619	
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	38,631	38,458	38,286	38,113	37,940	37,767	37,595	462,535
	b Debt Component (Line 6 x Debt Component x 1/12)		9,760	9,718	9,675	9,632	9,590	9,547	9,504	9,462	9,419	9,376	9,334	9,291	114,308
8	Investment Expenses														
	a Depreciation (E)		37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	37,375	448,504
	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		22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	22,667	272,004
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		109,297	109,082	108,866	108,651	108,436	108,220	108,005	107,789	107,574	107,359	107,143	106,928	1,297,351
	a Recoverable Costs Allocated to Energy		8,407	8,391	8,374	8,358	8,341	8,325	8,308	8,291	8,275	8,258	8,242	8,225	99,796
	b Recoverable Costs Allocated to Demand		100,890	100,691	100,492	100,293	100,094	99,896	99,697	99,498	99,299	99,100	98,901	98,703	1,197,554
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		8,169	8,161	8,149	8,142	8,131	8,120	8,104	8,084	8,064	8,048	8,019	7,990	97,180
13	Retail Demand-Related Recoverable Costs (I)		98,047	97,854	97,661	97,468	97,275	97,081	96,888	96,695	96,502	96,308	96,115	95,922	1,163,817
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		106,216	106,015	105,810	105,610	105,405	105,201	104,992	104,779	104,566	104,356	104,134	103,912	1,260,997

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1601
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		81,880	382,578	458,872	1,098,446	1,229,620	1,360,795	1,491,970	1,539,144	1,586,318	1,539,144	1,239,970	1,024,795	13,033,532
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	16,169,371	16,169,371
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	18,130,435	34,299,806	
3	Less: Accumulated Depreciation (C)	(1,504,305)	(1,575,014)	(1,645,723)	(1,716,431)	(1,787,140)	(1,857,849)	(1,928,557)	(1,999,266)	(2,069,975)	(2,140,684)	(2,211,392)	(2,282,101)	(2,352,810)	
4	CWIP - Non Interest Bearing	3,135,839	3,217,719	3,600,297	4,059,169	5,157,615	6,387,235	7,748,030	9,240,000	10,779,144	12,365,462	13,904,606	15,144,576	(0)	
5	Net Investment (Lines 2 + 3 + 4) (A)	19,761,969	19,773,140	20,085,009	20,473,173	21,500,910	22,659,821	23,949,908	25,371,169	26,839,604	28,355,213	29,823,649	30,992,910	31,946,996	
6	Average Net Investment		19,767,554	19,929,075	20,279,091	20,987,041	22,080,366	23,304,864	24,660,538	26,105,387	27,597,409	29,089,431	30,408,279	31,469,953	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		91,346	92,092	93,710	96,981	102,033	107,692	113,956	120,633	127,528	134,422	140,517	145,423	1,366,333
	b Debt Component (Line 6 x Debt Component x 1/12)		22,575	22,759	23,159	23,967	25,216	26,614	28,162	29,812	31,516	33,220	34,726	35,939	337,665
8	Investment Expenses														
	a Depreciation (E)		70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	70,709	848,504
	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)		184,629	185,560	187,577	191,657	197,958	205,015	212,827	221,154	229,753	238,351	245,952	252,070	2,552,502
	a Recoverable Costs Allocated to Energy		14,202	14,274	14,429	14,743	15,228	15,770	16,371	17,012	17,673	18,335	18,919	19,390	196,346
	b Recoverable Costs Allocated to Demand		170,427	171,286	173,148	176,914	182,730	189,244	196,456	204,142	212,079	220,016	227,032	232,680	2,356,156
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	13,883	14,041	14,362	14,843	15,383	15,969	16,587	17,223	17,867	18,407	18,835	191,199
13	Retail Demand-Related Recoverable Costs (I)		165,626	166,461	168,270	171,930	177,582	183,913	190,921	198,391	206,105	213,818	220,636	226,125	2,289,778
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		179,425	180,343	182,311	186,292	192,426	199,296	206,891	214,978	223,328	231,685	239,043	244,960	2,480,976

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E.s 1031, 1158, 1167, 1199, 1250, 1258, 1287, 1958
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	100,000	100,000	200,000
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	122,186,973	
3	Less: Accumulated Depreciation (C)	(35,551,259)	(35,961,693)	(36,372,127)	(36,782,562)	(37,192,996)	(37,603,430)	(38,013,865)	(38,424,299)	(38,834,733)	(39,245,167)	(39,655,602)	(40,066,036)	(40,476,470)	
4	CWIP - Non Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	100,000	200,000	
5	Net Investment (Lines 2 + 3 + 4) (A)	86,635,714	86,225,280	85,814,846	85,404,411	84,993,977	84,583,543	84,173,108	83,762,674	83,352,240	82,941,805	82,531,371	82,220,937	81,910,502	
6	Average Net Investment		86,430,497	86,020,063	85,609,628	85,199,194	84,788,760	84,378,325	83,967,891	83,557,457	83,147,022	82,736,588	82,376,154	82,065,720	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		399,395	397,499	395,602	393,705	391,809	389,912	388,016	386,119	384,222	382,326	380,660	379,226	4,668,491
	b Debt Component (Line 6 x Debt Component x 1/12)		98,704	98,235	97,766	97,297	96,829	96,360	95,891	95,423	94,954	94,485	94,074	93,719	1,153,737
8	Investment Expenses														
	a Depreciation (E)		400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	400,430	4,805,154
	b Amortization (F)		10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	10,005	120,058
	c Dismantlement		0	0	0	0	0	0	0	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)		908,533	906,168	903,803	901,437	899,072	896,707	894,341	891,976	889,611	887,245	885,168	883,379	10,747,440
	a Recoverable Costs Allocated to Energy		69,887	69,705	69,523	69,341	69,159	68,977	68,795	68,614	68,432	68,250	68,090	67,952	826,726
	b Recoverable Costs Allocated to Demand		838,646	836,463	834,279	832,096	829,913	827,729	825,546	823,362	821,179	818,996	817,078	815,427	9,920,714
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		67,903	67,794	67,653	67,551	67,415	67,283	67,106	66,898	66,690	66,508	66,246	66,006	805,053
13	Retail Demand-Related Recoverable Costs (I)		815,019	812,898	810,776	808,654	806,532	804,410	802,288	800,166	798,045	795,923	794,059	792,454	9,641,224
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		882,923	880,692	878,429	876,205	873,947	871,693	869,394	867,064	864,734	862,430	860,306	858,461	10,446,277

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) 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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.s 1272, 1404, 1628, 4418
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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)	(427,269)	(430,520)	
4	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	536,908	533,658	530,407	527,157	523,906	520,655	517,405	
6	Average Net Investment		554,787	551,536	548,286	545,035	541,784	538,534	535,283	532,033	528,782	525,531	522,281	519,030	
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	2,474	2,459	2,444	2,428	2,413	2,398	29,773
	b Debt Component (Line 6 x Debt Component x 1/12)		634	630	626	622	619	615	611	608	604	600	596	593	7,358
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	3,094	3,094	37,123
	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	6,335	6,317	6,298	6,279	6,261	6,242	76,138
	a Recoverable Costs Allocated to Energy		496	495	493	492	490	489	487	486	484	483	482	480	5,857
	b Recoverable Costs Allocated to Demand		5,952	5,935	5,917	5,900	5,883	5,865	5,848	5,831	5,814	5,796	5,779	5,762	70,281
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		482	481	480	479	478	477	475	474	472	471	469	466	5,703
13	Retail Demand-Related Recoverable Costs (I)		5,784	5,767	5,751	5,734	5,717	5,700	5,683	5,667	5,650	5,633	5,616	5,599	68,301
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,266	6,248	6,230	6,213	6,195	6,177	6,159	6,140	6,122	6,104	6,085	6,066	74,004

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Other $13,195; 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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(32,014)	(32,222)	(32,429)	(32,637)	(32,844)	(33,052)	(33,259)	(33,467)	(33,674)	(33,882)	(34,089)	(34,297)	(34,504)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	30,856	30,648	30,441	30,234	30,026	29,819	29,611	29,404	29,196	28,989	28,781	28,574	28,366	
6	Average Net Investment		30,752	30,545	30,337	30,130	29,922	29,715	29,507	29,300	29,092	28,885	28,678	28,470	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		142	141	140	139	138	137	136	135	134	133	133	132	1,642
	b Debt Component (Line 6 x Debt Component x 1/12)		35	35	35	34	34	34	34	33	33	33	33	33	406
8	Investment Expenses														
	a Depreciation (E)		207	207	207	207	207	207	207	207	207	207	207	207	2,490
	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	383	382	381	380	379	378	376	375	374	373	372	4,537
	a Recoverable Costs Allocated to Energy		30	29	29	29	29	29	29	29	29	29	29	29	349
	b Recoverable Costs Allocated to Demand		355	354	353	352	351	350	348	347	346	345	344	343	4,188
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	28	28	28	28	28	28	28	340
13	Retail Demand-Related Recoverable Costs (I)		345	344	343	342	341	340	339	338	337	335	334	333	4,070
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		374	373	372	370	369	368	367	366	365	363	362	361	4,410

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E.s 1175, 1191, 1305, 1330
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	13,997,696	
3	Less: Accumulated Depreciation (C)	(5,269,811)	(5,316,003)	(5,362,196)	(5,408,388)	(5,454,581)	(5,500,773)	(5,546,965)	(5,593,158)	(5,639,350)	(5,685,543)	(5,731,735)	(5,777,927)	(5,824,120)	
4	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	8,450,730	8,404,538	8,358,346	8,312,153	8,265,961	8,219,768	8,173,576	
6	Average Net Investment		8,704,789	8,658,596	8,612,404	8,566,211	8,520,019	8,473,827	8,427,634	8,381,442	8,335,249	8,289,057	8,242,865	8,196,672	
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	39,158	38,944	38,731	38,517	38,304	38,090	37,877	468,610
	b Debt Component (Line 6 x Debt Component x 1/12)		9,941	9,888	9,835	9,783	9,730	9,677	9,624	9,572	9,519	9,466	9,413	9,361	115,809
8	Investment Expenses														
	a Depreciation (E)		46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	46,192	554,309
	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	95,027	94,761	94,495	94,228	93,962	93,696	93,430	1,138,727
	a Recoverable Costs Allocated to Energy		7,412	7,392	7,371	7,351	7,330	7,310	7,289	7,269	7,248	7,228	7,207	7,187	87,594
	b Recoverable Costs Allocated to Demand		88,946	88,700	88,454	88,209	87,963	87,717	87,472	87,226	86,980	86,734	86,489	86,243	1,051,133
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		7,202	7,189	7,173	7,161	7,145	7,130	7,110	7,087	7,064	7,043	7,012	6,981	85,298
13	Retail Demand-Related Recoverable Costs (I)		86,440	86,201	85,963	85,724	85,485	85,246	85,007	84,768	84,530	84,291	84,052	83,813	1,021,520
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		93,642	93,390	93,135	92,885	92,630	92,376	92,118	91,856	91,594	91,334	91,064	90,794	1,106,818

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E.s 1218 & 1361
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
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		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project
P.E.s 1178, 1227, 1298
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,370	100,000
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		15,000	0	0	0	0	0	0	0	0	0	0	0	15,000
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	20,195,681	
3	Less: Accumulated Depreciation (C)	(5,508,806)	(5,560,452)	(5,627,097)	(5,693,743)	(5,760,389)	(5,827,035)	(5,893,680)	(5,960,326)	(6,026,972)	(6,093,618)	(6,160,263)	(6,226,909)	(6,293,555)	
4	CWIP - Non Interest Bearing	0	8,330	16,660	24,990	33,320	41,650	49,980	58,310	66,640	74,970	83,300	91,630	100,000	
5	Net Investment (Lines 2 + 3 + 4) (A)	14,686,875	14,643,559	14,585,243	14,526,928	14,468,612	14,410,296	14,351,980	14,293,665	14,235,349	14,177,033	14,118,717	14,060,402	14,002,126	
6	Average Net Investment		14,665,217	14,614,401	14,556,085	14,497,770	14,439,454	14,381,138	14,322,822	14,264,507	14,206,191	14,147,875	14,089,559	14,031,264	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		67,768	67,533	67,264	66,994	66,725	66,455	66,186	65,916	65,647	65,377	65,108	64,838	795,811
	b Debt Component (Line 6 x Debt Component x 1/12)		16,748	16,690	16,623	16,556	16,490	16,423	16,357	16,290	16,223	16,157	16,090	16,024	196,671
8	Investment Expenses														
	a Depreciation (E)		66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	66,646	799,749
	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)		151,161	150,869	150,532	150,196	149,860	149,524	149,188	148,852	148,516	148,180	147,844	147,508	1,792,231
	a Recoverable Costs Allocated to Energy		11,628	11,605	11,579	11,554	11,528	11,502	11,476	11,450	11,424	11,398	11,373	11,347	137,864
	b Recoverable Costs Allocated to Demand		139,534	139,263	138,953	138,643	138,333	138,022	137,712	137,402	137,092	136,782	136,471	136,161	1,654,367
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		11,298	11,287	11,268	11,255	11,237	11,219	11,194	11,164	11,134	11,108	11,065	11,022	134,250
13	Retail Demand-Related Recoverable Costs (I)		135,603	135,340	135,038	134,737	134,435	134,134	133,832	133,531	133,230	132,928	132,627	132,325	1,607,760
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		146,900	146,627	146,306	145,992	145,672	145,353	145,027	144,695	144,363	144,036	143,691	143,347	1,742,010

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.

Docket No. 20180007-EI
2019 Projection Filing
Exhibit CSB-3, Page 27 of 42

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E.s 0433, 1204 & 1299
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	6,167,068	
3	Less: Accumulated Depreciation (C)	(2,158,179)	(2,178,538)	(2,198,898)	(2,219,258)	(2,239,617)	(2,259,977)	(2,280,337)	(2,300,697)	(2,321,056)	(2,341,416)	(2,361,776)	(2,382,135)	(2,402,495)	
4	CWIP - Non Interest Bearing	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	685,345	
5	Net Investment (Lines 2 + 3 + 4) (A)	4,694,234	4,673,874	4,653,515	4,633,155	4,612,795	4,592,436	4,572,076	4,551,716	4,531,357	4,510,997	4,490,637	4,470,277	4,449,918	
6	Average Net Investment		4,684,054	4,663,695	4,643,335	4,622,975	4,602,615	4,582,256	4,561,896	4,541,536	4,521,177	4,500,817	4,480,457	4,460,098	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		21,645	21,551	21,457	21,363	21,269	21,175	21,081	20,986	20,892	20,798	20,704	20,610	253,531
	b Debt Component (Line 6 x Debt Component x 1/12)		5,349	5,326	5,303	5,279	5,256	5,233	5,210	5,186	5,163	5,140	5,117	5,093	62,656
8	Investment Expenses														
	a Depreciation (E)		20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	20,360	244,316
	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)		47,354	47,237	47,119	47,002	46,885	46,767	46,650	46,533	46,415	46,298	46,181	46,063	560,503
	a Recoverable Costs Allocated to Energy		3,643	3,634	3,625	3,616	3,607	3,597	3,588	3,579	3,570	3,561	3,552	3,543	43,116
	b Recoverable Costs Allocated to Demand		43,711	43,603	43,495	43,386	43,278	43,170	43,061	42,953	42,845	42,737	42,628	42,520	517,387
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		3,539	3,534	3,527	3,522	3,516	3,509	3,500	3,490	3,480	3,470	3,456	3,442	41,985
13	Retail Demand-Related Recoverable Costs (I)		42,480	42,375	42,269	42,164	42,059	41,954	41,848	41,743	41,638	41,533	41,427	41,322	502,811
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		46,019	45,909	45,796	45,686	45,574	45,463	45,349	45,233	45,117	45,003	44,883	44,764	544,796

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Compliance Program

P.E.s 0560, 0860, 1034, 1035, 1036, 1037, 1067, 1095, 1168, 1188, 1222, 1233, 1279, 1288, 1362, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1684, 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 1809, 1810, 1824, 1826, 1909, 1911, 1913, 1950
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		127,468	127,468	127,468	127,468	366,468	737,106	857,468	1,406,975	1,357,468	1,107,468	1,137,468	1,179,852	8,660,145
	b Clearings to Plant		4,442,256	0	0	179,337	0	130,000	0	0	0	0	480,082	7,563,152	12,794,827
	c Retirements		0	0	0	0	0	0	130,000	0	0	0	0	0	130,000
	d Cost of Removal		0	0	0	0	0	3,000	0	0	16,500	16,500	17,000	0	53,000
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	1,347,815,790	1,352,258,046	1,352,258,046	1,352,258,046	1,352,437,383	1,352,437,383	1,352,567,383	1,352,437,383	1,352,437,383	1,352,437,383	1,352,437,383	1,352,917,464	1,360,480,617	
3	Less: Accumulated Depreciation (C)	(286,635,074)	(290,525,490)	(294,430,565)	(298,335,640)	(302,240,715)	(306,146,113)	(310,048,511)	(313,824,338)	(317,729,736)	(321,618,634)	(325,507,532)	(329,395,930)	(333,302,913)	
4	CWIP - Non Interest Bearing	10,308,217	5,993,429	6,120,897	6,248,365	6,196,496	6,562,964	7,170,070	8,027,538	9,434,513	10,791,981	11,899,449	12,556,836	6,173,535	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,071,488,933	1,067,725,985	1,063,948,378	1,060,170,771	1,056,393,164	1,052,854,234	1,049,688,942	1,046,640,583	1,044,142,160	1,041,610,730	1,038,829,300	1,036,078,370	1,033,351,239	
6	Average Net Investment		1,069,607,459	1,065,837,182	1,062,059,574	1,058,281,967	1,054,623,699	1,051,271,588	1,048,164,762	1,045,391,371	1,042,876,445	1,040,220,015	1,037,453,835	1,034,714,804	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,942,656	4,925,234	4,907,777	4,890,321	4,873,416	4,857,926	4,843,569	4,830,754	4,819,132	4,806,857	4,794,074	4,781,417	58,273,133
	b Debt Component (Line 6 x Debt Component x 1/12)		1,221,492	1,217,186	1,212,872	1,208,558	1,204,380	1,200,552	1,197,004	1,193,837	1,190,965	1,187,931	1,184,772	1,181,644	14,401,194
8	Investment Expenses														
	a Depreciation (E)		3,863,371	3,878,030	3,878,030	3,878,030	3,878,353	3,878,353	3,878,782	3,878,353	3,878,353	3,878,353	3,878,353	3,879,937	46,526,299
	b Amortization (F)		27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	27,045	324,539
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	547,440	6,569,285
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,602,004	10,594,935	10,573,165	10,551,395	10,530,635	10,511,317	10,493,841	10,477,429	10,462,935	10,447,626	10,431,685	10,417,484	126,094,451
	a Recoverable Costs Allocated to Energy		815,539	814,995	813,320	811,646	810,049	808,563	807,219	805,956	804,841	803,664	802,437	801,345	9,699,573
	b Recoverable Costs Allocated to Demand		9,786,465	9,779,940	9,759,845	9,739,749	9,720,586	9,702,754	9,686,622	9,671,473	9,658,094	9,643,963	9,629,248	9,616,139	116,394,877
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		792,386	792,652	791,442	790,688	789,617	788,696	787,396	785,805	784,355	783,150	780,711	778,396	9,445,294
13	Retail Demand-Related Recoverable Costs (I)		9,510,758	9,504,417	9,484,887	9,465,358	9,446,735	9,429,405	9,413,728	9,399,005	9,386,003	9,372,270	9,357,970	9,345,230	113,115,766
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,303,144	10,297,069	10,276,329	10,256,046	10,236,352	10,218,101	10,201,124	10,184,810	10,170,358	10,155,420	10,138,680	10,123,626	122,561,060

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $791,000,404; Smith $229,742; Daniel $373,633,349, Scherer $182,952,295. Ending Balances: Crist $803,485,894; Smith $229,742; Daniel $373,633,349, Scherer $183,131,632.
(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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.s 0831, 0861 & 1280
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	832,922	
3	Less: Accumulated Depreciation (C)	(16,492)	(19,240)	(21,989)	(24,738)	(27,486)	(30,235)	(32,984)	(35,732)	(38,481)	(41,230)	(43,978)	(46,727)	(49,476)	
4	CWIP - Non Interest Bearing	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	
5	Net Investment (Lines 2 + 3 + 4) (A)	1,116,430	1,113,681	1,110,932	1,108,184	1,105,435	1,102,687	1,099,938	1,097,189	1,094,441	1,091,692	1,088,943	1,086,195	1,083,446	
6	Average Net Investment		1,115,055	1,112,307	1,109,558	1,106,809	1,104,061	1,101,312	1,098,564	1,095,815	1,093,066	1,090,318	1,087,569	1,084,820	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,153	5,140	5,127	5,115	5,102	5,089	5,076	5,064	5,051	5,038	5,026	5,013	60,994
	b Debt Component (Line 6 x Debt Component x 1/12)		1,273	1,270	1,267	1,264	1,261	1,258	1,255	1,251	1,248	1,245	1,242	1,239	15,074
8	Investment Expenses														
	a Depreciation (E)		2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	32,984
	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)		9,175	9,159	9,143	9,127	9,111	9,096	9,080	9,064	9,048	9,032	9,016	9,000	109,051
	a Recoverable Costs Allocated to Energy		706	705	703	702	701	700	698	697	696	695	694	692	8,389
	b Recoverable Costs Allocated to Demand		8,469	8,454	8,440	8,425	8,410	8,396	8,381	8,367	8,352	8,337	8,323	8,308	100,662
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		686	685	684	684	683	682	681	680	678	677	675	673	8,169
13	Retail Demand-Related Recoverable Costs (I)		8,230	8,216	8,202	8,188	8,174	8,159	8,145	8,131	8,117	8,102	8,088	8,074	97,827
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,916	8,901	8,886	8,872	8,857	8,842	8,826	8,811	8,795	8,780	8,763	8,747	105,995

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.

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2019 Projection Filing
Exhibit CSB-3, Page 30 of 42

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Coal Combustion Residuals
P.E.s 0404, 0412, 0424, 0514, 1597, 1598, 1599, 1641, 1997, 4405, 4430, 4440, 6756, 6757, 6759, 6764, 6765, CCR-C, CCR-D, CCR-S
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		6,355,785	6,630,932	7,609,577	5,480,221	4,605,497	4,425,255	2,880,461	2,909,739	2,648,579	2,424,232	2,347,619	2,447,619	50,765,515
	b Clearings to Plant		0	0	0	10,744,993	0	0	13,726,988	13,900,848	0	0	0	0	38,372,829
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	3,406,029	3,406,029	3,406,029	3,406,029	14,151,022	14,151,022	14,151,022	27,878,010	41,778,858	41,778,858	41,778,858	41,778,858	41,778,858	
3	Less: Accumulated Depreciation (C)	(37,041,296)	(37,104,517)	(37,167,738)	(37,230,959)	(37,294,181)	(37,376,743)	(37,459,305)	(37,541,868)	(37,649,138)	(37,780,041)	(37,910,943)	(38,041,845)	(38,172,747)	
4	CWIP - Non Interest Bearing	53,655,054	60,010,840	66,641,771	74,251,348	68,986,576	73,592,072	78,017,327	67,170,801	56,179,692	58,828,271	61,252,503	63,600,121	66,047,740	
5	Net Investment (Lines 2 + 3 + 4) (A)	20,019,788	26,312,352	32,880,062	40,426,418	45,843,417	50,366,352	54,709,045	57,506,944	60,309,412	62,827,089	65,120,418	67,337,135	69,653,851	
6	Average Net Investment		23,166,070	29,596,207	36,653,240	43,134,918	48,104,884	52,537,698	56,107,994	58,908,178	61,568,250	63,973,753	66,228,776	68,495,493	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		107,050	136,764	169,375	199,326	222,293	242,777	259,275	272,215	284,507	295,623	306,043	316,518	2,811,765
	b Debt Component (Line 6 x Debt Component x 1/12)		26,456	33,799	41,858	49,260	54,936	59,998	64,075	67,273	70,311	73,058	75,633	78,222	694,879
8	Investment Expenses														
	a Depreciation (E)		8,361	8,361	8,361	8,361	27,702	27,702	27,702	52,410	76,042	76,042	76,042	76,042	473,124
	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		1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	1,199	14,383
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		197,926	234,983	275,652	313,006	360,989	386,536	407,111	447,957	486,919	500,782	513,777	526,840	4,652,479
	a Recoverable Costs Allocated to Energy		15,225	18,076	21,204	24,077	27,768	29,734	31,316	34,458	37,455	38,522	39,521	40,526	357,883
	b Recoverable Costs Allocated to Demand		182,701	216,907	254,448	288,929	333,221	356,802	375,795	413,499	449,463	462,260	474,256	486,314	4,294,596
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		14,793	17,580	20,634	23,456	27,068	29,003	30,547	33,597	36,502	37,538	38,451	39,366	348,534
13	Retail Demand-Related Recoverable Costs (I)		177,554	210,796	247,280	280,789	323,833	346,750	365,208	401,850	436,801	449,237	460,895	472,614	4,173,607
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		192,347	228,376	267,914	304,245	350,901	375,753	395,755	435,446	473,303	486,775	499,346	511,979	4,522,141

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $441,896; Smith $1,404,285; Scherer $781,943; Scholz $673181; Daniel $104,724. Ending Balances: Crist $441,896; Smith $1,404,285; Scherer $25,253,924; Scholz $14,574,029; 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) 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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: Steam Electric Effluent Limitations Guidelines
P.E.s 1193, 1912 & 6754
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		198,474	23,474	23,474	23,474	23,474	23,475	23,475	23,475	23,475	23,475	23,475	23,475	456,695
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	5,655,259	
3	Less: Accumulated Depreciation (C)	(185,745)	(204,408)	(223,070)	(241,732)	(260,395)	(279,057)	(297,719)	(316,382)	(335,044)	(353,706)	(372,369)	(391,031)	(409,694)	
4	CWIP - Non Interest Bearing	0	198,474	221,948	245,422	268,896	292,370	315,845	339,320	362,795	386,270	409,745	433,220	456,695	
5	Net Investment (Lines 2 + 3 + 4) (A)	5,469,514	5,649,325	5,654,137	5,658,949	5,663,760	5,668,572	5,673,384	5,678,197	5,683,010	5,687,822	5,692,635	5,697,448	5,702,260	
6	Average Net Investment		5,559,419	5,651,731	5,656,543	5,661,354	5,666,166	5,670,978	5,675,791	5,680,603	5,685,416	5,690,229	5,695,041	5,699,854	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		25,690	26,117	26,139	26,161	26,183	26,206	26,228	26,250	26,272	26,295	26,317	26,339	314,196
	b Debt Component (Line 6 x Debt Component x 1/12)		6,349	6,454	6,460	6,465	6,471	6,476	6,482	6,487	6,493	6,498	6,504	6,509	77,648
8	Investment Expenses														
	a Depreciation (E)		18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	18,662	223,948
	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)		50,701	51,233	51,261	51,289	51,316	51,344	51,372	51,400	51,427	51,455	51,483	51,511	615,793
	a Recoverable Costs Allocated to Energy		3,900	3,941	3,943	3,945	3,947	3,950	3,952	3,954	3,956	3,958	3,960	3,962	47,369
	b Recoverable Costs Allocated to Demand		46,801	47,292	47,318	47,343	47,369	47,395	47,420	47,446	47,471	47,497	47,523	47,548	568,424
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		3,789	3,833	3,837	3,843	3,848	3,853	3,855	3,855	3,855	3,857	3,853	3,849	46,127
13	Retail Demand-Related Recoverable Costs (I)		45,483	45,960	45,985	46,010	46,035	46,059	46,084	46,109	46,134	46,159	46,184	46,209	552,410
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		49,272	49,793	49,822	49,853	49,882	49,912	49,939	49,964	49,989	50,016	50,037	50,058	598,537

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 Projected Period Amount
January 2019 - December 2019
Return on Capital Investments, Depreciation and Taxes
For Project: 316(b) Cooling Water Intake Structure Regulation
P.E. 1691
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		0	100,000	100,000	0	0	50,000	400,000	950,000	125,000	125,000	125,000	25,000	2,000,000
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	2,000,000	2,000,000
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	2,000,000	
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	100,000	200,000	200,000	200,000	250,000	650,000	1,600,000	1,725,000	1,850,000	1,975,000	0	
5	Net Investment (Lines 2 + 3 + 4) (A)	0	0	100,000	200,000	200,000	200,000	250,000	650,000	1,600,000	1,725,000	1,850,000	1,975,000	2,000,000	
6	Average Net Investment		0	50,000	150,000	200,000	200,000	225,000	450,000	1,125,000	1,662,500	1,787,500	1,912,500	1,987,500	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	231	693	924	924	1,040	2,079	5,199	7,682	8,260	8,838	9,184	45,055
	b Debt Component (Line 6 x Debt Component x 1/12)		0	57	171	228	228	257	514	1,285	1,899	2,041	2,184	2,270	11,135
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	288	864	1,153	1,153	1,297	2,593	6,483	9,581	10,301	11,022	11,454	56,189
	a Recoverable Costs Allocated to Energy		0	22	66	89	89	100	199	499	737	792	848	881	4,322
	b Recoverable Costs Allocated to Demand		0	266	798	1,064	1,064	1,197	2,394	5,985	8,844	9,509	10,174	10,573	51,867
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	22	65	86	86	97	195	486	718	772	825	856	4,208
13	Retail Demand-Related Recoverable Costs (I)		0	258	775	1,034	1,034	1,163	2,326	5,816	8,595	9,241	9,887	10,275	50,406
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	280	840	1,120	1,120	1,261	2,521	6,302	9,313	10,013	10,712	11,131	54,614

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 Projected Period Amount
January 2019 - December 2019
Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury 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	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		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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 3P.
(E) Line 8 is reported on Schedule 2P.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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 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	7,649	7,649	7,649	7,135	6,251	5,822	5,317	4,766	4,224	3,723	2,549	1,565	435	
	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	7,649	7,649	7,649	7,135	6,251	5,822	5,317	4,766	4,224	3,723	2,549	1,565	435	
4	Average Net Working Capital Balance		7,649	7,649	7,392	6,693	6,036	5,569	5,042	4,495	3,974	3,136	2,057	1,000	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		35	35	34	31	28	26	23	21	18	14	10	5	280
	b Debt Component (Line 4 x Debt Component x 1/12)		9	9	8	8	7	6	6	5	5	4	2	1	69
6	Total Return Component (D)		44	44	43	39	35	32	29	26	23	18	12	6	350
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	514	884	430	504	551	542	501	1,174	984	1,130	7,214
8	Net Expenses (E)		0	0	514	884	430	504	551	542	501	1,174	984	1,130	7,214
9	Total System Recoverable Expenses (Lines 6 + 8)		44	44	556	923	464	536	580	568	524	1,192	996	1,136	7,564
	a Recoverable Costs Allocated to Energy		3	3	517	887	432	507	553	544	503	1,175	985	1,131	7,241
	b Recoverable Costs Allocated to Demand		41	41	39	36	32	30	27	24	21	17	11	5	323
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	503	864	421	494	540	530	490	1,145	958	1,098	7,051
13	Retail Demand-Related Recoverable Costs (C)		40	40	38	35	31	29	26	23	21	16	11	5	314
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		43	43	541	899	453	523	566	553	511	1,161	969	1,103	7,365

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.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period 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	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 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	9,789	9,789	9,789	9,789	9,789	8,815	6,999	5,178	2,528	1,902	1,902	1,902	1,902	
	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	9,789	9,789	9,789	9,789	9,789	8,815	6,999	5,178	2,528	1,902	1,902	1,902	1,902	
4	Average Net Working Capital Balance		9,789	9,789	9,789	9,789	9,302	7,907	6,089	3,853	2,215	1,902	1,902	1,902	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		45	45	45	45	43	37	28	18	10	9	9	9	343
	b Debt Component (Line 4 x Debt Component x 1/12)		11	11	11	11	11	9	7	4	3	2	2	2	85
6	Total Return Component (D)		56	56	56	56	54	46	35	22	13	11	11	11	428
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	974	1,816	1,820	2,650	626	0	0	0	7,887
8	Net Expenses (E)		0	0	0	0	974	1,816	1,820	2,650	626	0	0	0	7,887
9	Total System Recoverable Expenses (Lines 6 + 8)		56	56	56	56	1,027	1,862	1,855	2,673	639	11	11	11	8,315
	a Recoverable Costs Allocated to Energy		4	4	4	4	978	1,820	1,823	2,652	627	1	1	1	7,920
	b Recoverable Costs Allocated to Demand		52	52	52	52	49	42	32	21	12	10	10	10	395
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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	953	1,775	1,778	2,586	611	1	1	1	7,723
13	Retail Demand-Related Recoverable Costs (C)		51	51	51	51	48	41	31	20	11	10	10	10	384
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		55	55	55	55	1,001	1,816	1,810	2,606	622	11	11	11	8,107

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.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Working Capital, SO2 Expenses
For Project: SO2 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	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	6,299,023	6,296,667	6,294,766	6,292,872	6,290,989	6,287,546	6,282,862	6,277,818	6,272,721	6,268,501	6,265,175	6,263,266	6,261,028	
	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)	(249)	(230)	(210)	(191)	(171)	(152)	(132)	(113)	(93)	(74)	(54)	(35)	
3	Total Working Capital Balance	6,298,755	6,296,418	6,294,537	6,292,662	6,290,799	6,287,375	6,282,711	6,277,686	6,272,608	6,268,408	6,265,101	6,263,212	6,260,993	
4	Average Net Working Capital Balance		6,297,587	6,295,477	6,293,599	6,291,730	6,289,087	6,285,043	6,280,198	6,275,147	6,270,508	6,266,755	6,264,156	6,262,102	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		29,101	29,091	29,083	29,074	29,062	29,043	29,021	28,997	28,976	28,959	28,947	28,937	348,291
	b Debt Component (Line 4 x Debt Component x 1/12)		7,192	7,189	7,187	7,185	7,182	7,178	7,172	7,166	7,161	7,157	7,154	7,151	86,074
6	Total Return Component (D)		36,293	36,281	36,270	36,259	36,244	36,221	36,193	36,164	36,137	36,115	36,100	36,089	434,365
7	Expenses														
	a Gains		(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(234)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		2,356	1,901	1,894	1,883	3,443	4,684	5,045	5,097	4,220	3,327	1,909	2,238	37,996
8	Net Expenses (E)		2,337	1,882	1,874	1,864	3,424	4,664	5,025	5,077	4,200	3,307	1,889	2,219	37,762
9	Total System Recoverable Expenses (Lines 6 + 8)		38,630	38,163	38,144	38,123	39,668	40,885	41,218	41,241	40,337	39,422	37,990	38,307	472,127
	a Recoverable Costs Allocated to Energy		5,128	4,673	4,664	4,653	6,212	7,450	7,809	7,859	6,980	6,085	4,666	4,995	71,175
	b Recoverable Costs Allocated to Demand		33,501	33,490	33,480	33,470	33,456	33,434	33,409	33,382	33,357	33,337	33,323	33,312	400,953
10	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		4,983	4,545	4,539	4,533	6,055	7,267	7,617	7,662	6,802	5,930	4,540	4,852	69,325
13	Retail Demand-Related Recoverable Costs (C)		32,557	32,547	32,537	32,527	32,513	32,493	32,468	32,441	32,417	32,398	32,385	32,374	389,657
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		37,540	37,091	37,075	37,060	38,569	39,760	40,085	40,104	39,220	38,328	36,925	37,226	458,982

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.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019
Return on Working Capital, Amortization Expense
For Project: Regulatory Asset Smith Units 1 & 2
For Retired P.E.s 1413, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1461, 1462, 1468, 1469, 1647, 1620, 1638
(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	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	88,495	87,947	87,399	86,851	86,303	85,755	1,065,224
	b Debt Component (Line 6 x Debt Component x 1/12)		22,682	22,547	22,412	22,276	22,141	22,005	21,870	21,735	21,599	21,464	21,328	21,193	263,252
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	228,944	228,260	227,577	226,894	226,210	225,527	2,751,425
	a Recoverable Costs Allocated to Energy		17,926	17,874	17,821	17,769	17,716	17,664	17,611	17,558	17,506	17,453	17,401	17,348	211,648
	b Recoverable Costs Allocated to Demand		215,118	214,487	213,856	213,225	212,594	211,964	211,333	210,702	210,071	209,440	208,809	208,179	2,539,777
8	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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)		17,418	17,384	17,342	17,310	17,269	17,230	17,179	17,119	17,060	17,008	16,930	16,851	206,100
11	Retail Demand-Related Recoverable Costs (H)		209,057	208,444	207,831	207,218	206,605	205,992	205,379	204,766	204,153	203,540	202,927	202,314	2,468,226
12	Total Jurisdictional Recoverable Costs (Lines 10 + 11)		226,475	225,828	225,173	224,528	223,874	223,222	222,558	221,885	221,213	220,548	219,857	219,165	2,674,326

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 6P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2019 - December 2019

Rate Class	(A) Average 12 CP Load Factor at Meter (%)	(B) Jan - Dec. 2019 Projected Sales at Meter (kWh)	(C) Projected Avg 12 CP at Meter (kW)	(D) Demand Loss Expansion Factor	(E) Energy Loss Expansion Factor	(F) Projected Sales at Generation (kWh)	(G) Projected Avg 12 CP at Generation (kW)	(H) Percentage of kWh Sales at Generation (%)	(I) Percentage of 12 CP Demand at Generation (%)
RS, RSVP, RSTOU	57.542346%	5,300,092,000	1,051,458	1.00609343	1.00559591	5,329,750,838	1,057,865	49.48355%	57.36917%
GS	63.463164%	299,818,000	53,930	1.00608241	1.00559477	301,495,413	54,258	2.79920%	2.94248%
GSD, GSDT, GSTOU	73.488079%	2,546,024,000	395,495	1.00590017	1.00544671	2,559,891,454	397,829	23.76706%	21.57471%
LP, LPT	82.760718%	828,364,000	114,260	0.98747379	0.99210885	821,827,255	112,828	7.63017%	6.11881%
PX, PXT, RTP, SBS	85.375300%	1,642,739,000	219,651	0.96884429	0.97666479	1,604,405,340	212,807	14.89594%	11.54077%
OS-I/II	416.652542%	104,912,000	2,874	1.00619545	1.00560119	105,499,632	2,892	0.97950%	0.15685%
OS-III	99.799021%	47,618,000	5,447	1.00617773	1.00558881	47,884,128	5,480	0.44458%	0.29721%
TOTAL		10,769,567,000	1,843,115			10,770,754,060	1,843,960	100.00000%	100.00000%

Notes:
(A) Average 12 CP load factor based on actual 2015 load research data
(B) Projected kWh sales for the period January 2019 - December 2019
(C) Calculated: (Col 2) / (8,760 x Col 1), (8,760 hours = the # of hours in 1 year)
(F) Column B x Column E
(G) Column C x Column D
(H) Column F / total for Column F
(I) Column I / total for Column I

Schedule 7P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2019 - December 2019

Rate Class	(A) Percentage of kWh Sales at Generation (%)	(B) Percentage of 12 CP Demand at Generation (%)	(C) Energy-Related Costs	(D) Demand-Related Costs	(E) Total Environmental Costs	(F) Projected Sales at Meter (kWh)	(G) Environmental Cost Recovery Factors (¢/kWh)
RS, RSVP, RSTOU	49.48355%	57.36917%	16,033,653	79,893,139	95,926,792	5,300,092,000	1.810
GS	2.79920%	2.94248%	906,996	4,097,740	5,004,736	299,818,000	1.669
GSD, GSDT, GSTOU	23.76706%	21.57471%	7,700,999	30,045,255	37,746,254	2,546,024,000	1.483
LP, LPT	7.63017%	6.11881%	2,472,327	8,521,144	10,993,471	828,364,000	1.327
PX, PXT, RTP, SBS	14.89594%	11.54077%	4,826,580	16,071,844	20,898,424	1,642,739,000	1.272
OS-I/II	0.97950%	0.15685%	317,377	218,432	535,809	104,912,000	0.511
OS-III	0.44458%	0.29721%	144,053	413,899	557,952	47,618,000	1.172
TOTAL	100.00000%	100.00000%	$32,401,985	$139,261,453	171,663,438	10,769,567,000	1.594

Notes:
(A) From Schedule 6P, Col H
(B) From Schedule 6P, Col I
(C) Column A x Total Energy $ from Schedule 1P, line 5
(D) Column B x Total Demand $ from Schedule 1P, line 5
(E) Column C + Column D
(F) Projected kWh sales for the period January 2019 - December 2019
(G) Column E x 100 / Column F

Schedule 8P
Page 1 of 1

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 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-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2019 - December 2019

For Project: Scherer - Air Quality Compliance and CCR Programs

P.E.s 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 6754, 6756, 6757, 6759, 6764, 6765, CCR-S
(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	12-Month Total
1	Investments														
	a Expenditures/Additions		1,633,369	1,458,369	1,458,369	1,458,369	1,458,371	1,472,121	110,142	110,142	110,142	110,142	110,142	110,142	9,599,820
	b Clearings to Plant		0	0	0	10,924,330	0	0	13,726,988	0	0	0	0	0	24,651,318
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Cost of Removal		0	0	0	0	0	0	0	0	16,500	16,500	17,000	0	50,000
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base	183,734,238	183,734,238	183,734,238	183,734,238	194,658,568	194,658,568	194,658,568	208,385,556	208,385,556	208,385,556	208,385,556	208,385,556	208,385,556	
3	Less: Accumulated Depreciation	(28,407,990)	(28,740,947)	(29,073,904)	(29,406,862)	(29,739,819)	(30,092,440)	(30,445,061)	(30,797,682)	(31,175,012)	(31,535,841)	(31,896,671)	(32,257,001)	(32,634,330)	
4	Working Capital (Emissions)	16,829	16,829	16,829	16,306	15,405	14,952	14,421	13,841	13,271	12,743	11,546	10,543	9,391	
5	CWIP - Non Interest Bearing	17,550,290	19,183,659	20,642,028	22,100,397	12,634,436	14,092,807	15,564,928	1,948,082	2,058,224	2,168,366	2,278,508	2,388,650	2,498,792	
6	Net Investment (Lines 2 + 3 + 4 + 5)	172,893,368	174,193,780	175,319,192	176,444,080	177,568,590	178,673,888	179,792,857	179,549,798	179,282,040	179,030,824	178,778,940	178,527,749	178,259,410	
7	Average Net Investment		173,543,574	174,756,486	175,881,636	177,006,335	178,121,239	179,233,372	179,671,327	179,415,919	179,156,432	178,904,882	178,653,345	178,393,580	
8	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12)		801,945	807,550	812,749	817,946	823,098	828,237	830,261	829,081	827,882	826,719	825,557	824,357	9,855,383
	b Debt Component (Line 6 x Debt Component x 1/12)		198,187	199,572	200,857	202,141	203,414	204,685	205,185	204,893	204,597	204,309	204,022	203,725	2,435,587
9	Investment Expenses														
	a Depreciation		329,937	329,937	329,937	329,937	349,601	349,601	349,601	374,310	374,310	374,310	374,310	374,310	4,240,101
	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		24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	24,835	298,024
	e Other		0	0	0	0	0	0	0	0	0	0	0	0	0
10	O&M and Emissions														
	a O&M Expense		128,976	308,222	375,285	170,924	157,933	145,841	146,277	146,399	146,386	129,906	142,158	130,649	2,128,956
	b Emissions Expense		0	0	629	1,082	969	1,378	1,164	1,132	1,159	1,439	1,207	1,385	11,544
11	Total System Recoverable Expenses (Lines 8 + 9 + 10)		1,486,900	1,673,136	1,747,312	1,549,886	1,562,871	1,557,598	1,560,343	1,583,670	1,582,189	1,564,538	1,575,109	1,562,282	19,005,834
	a Recoverable Costs Allocated to Energy		233,328	413,069	481,174	277,860	266,751	255,575	255,990	257,775	257,766	241,442	253,349	241,927	3,436,007
	b Recoverable Costs Allocated to Demand		1,253,572	1,260,067	1,266,138	1,272,026	1,296,119	1,302,023	1,304,352	1,325,895	1,324,423	1,323,096	1,321,760	1,320,354	15,569,827
12	Energy Jurisdictional Factor		0.9704455	0.9714195	0.9719331	0.9730117	0.9736090	0.9742609	0.9742742	0.9738285	0.9733777	0.9733073	0.9717584	0.9701974	
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		226,704	401,745	468,230	270,685	260,023	249,295	249,704	251,330	251,204	235,280	246,490	234,999	3,345,689
15	Retail Demand-Related Recoverable Costs		1,218,256	1,224,568	1,230,468	1,236,190	1,259,605	1,265,342	1,267,606	1,288,541	1,287,111	1,285,821	1,284,523	1,283,157	15,131,189
16	Total Jurisdictional Recoverable Costs (Lines 14 + 15)		1,444,960	1,626,313	1,698,698	1,506,876	1,519,628	1,514,637	1,517,310	1,539,871	1,538,316	1,521,101	1,531,013	1,518,156	18,476,878
17	Scherer/Flint Credit(24%)		346,790	390,315	407,688	361,650	364,711	363,513	364,154	369,569	369,196	365,064	367,443	364,357	4,434,451

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Air Quality Assurance Testing
PEs 1006 and 1244

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This line item 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).

Accomplishments:
The RATA test trailer and CEMs system was replaced during the 2010 recovery period. These replacements provide Gulf with the accuracy and reliability needed to accurately measure SO_2, NOx, and CO_2 and to further maintain compliance with CAAA requirements.

Project-to-Date: Plant-in-service of $65,000 projected at December of 2019

Progress Summary: In 2019, Gulf will replace the analyzers located in the RATA test trailer.

Projections: Expenditures reflected in the 2019 projection filing for this line item total $65,000.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 34
PARTY: GULF POWER COMPANY (GULF)
(DIRECT)
DESCRIPTION: Richard M. Markey RMM-1

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 5, 6 & 7 Precipitator Projects
PEs 1038, 1119, 1216, 1243 and 1249

FPSC Approval: Order No. PSC-94-0044-FOF-EI
Order No. PSC-09-0759-FOF-EI

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.

Accomplishments:
The precipitators have successfully reduced particulate emissions. The upgraded Crist Unit 7 precipitator was placed in service during 2004 as part of the FDEP agreement. The Plant Crist Unit 6 precipitator upgrade was placed in service in April 2012. The digital control system for the Unit 6 precipitator was upgraded during 2015.

Project-to-Date: Plant-in-service of $33,677,323 projected at December 2019.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 7 Flue Gas Conditioning
PE 1228

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This project included 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 during July 2005.

Accomplishments:
The system enhanced particulate removal in the precipitator.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Low NO_x Burners, Crist 6 & 7
PEs 1234, 1236, 1242 and 1284

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Low NO_x burners are unique burners installed to decrease the NO_x emissions that are formed during the combustion process. This equipment was installed to meet the requirements of the 1990 Clean Air Act Amendments.

Accomplishments:
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 during the 2003-2004 time frame and the Crist Unit 6 burners were replaced during December 2005. The digital control systems for the Unit 6 and Unit 7 Low NOx burners were upgraded during 2015. The Crist Unit 7 band gas canes on the Low NOx burners were upgraded with new retractable gas gun burning technology during 2016. Additional gas gun upgrades were installed in 2018.

Project-to-Date: Plant-in-service of $13,634,258 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CEMs – Plant Crist and Daniel
PEs 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1312, 1316, 1323, 1324, 1325, 1357, 1358, 1364, 1558, 1570, 1592, 1658, 1829and 1830

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Continuous Emission Monitoring (CEM) line item 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 line item. All CEMs monitors were installed pursuant to the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The systems at both Gulf and Mississippi Power continue to successfully exceed routine quality assurance/quality control (QA/QC) audits as required by the 1990 CAAA.

Project-to-Date: Plant-in-service of $4,690,600 projected at December 2019.

Progress Summary:
The Plant Daniel Units 1 & 2 gas analyzers were replaced during 2005 and the flow monitors were replaced during 2007. During the 2009 recovery period, the CEMS project included replacement of opacity monitors at Plant Crist on Units 4 through 7 and the installation of CEMs equipment for the new Plant Crist scrubber stack to monitor SO_2, NOx, CO_2 and flow. Plant Crist completed the installation of two CEMS bypass monitoring systems for Units 4 through 7 in the 2011-2012 timeframe. In 2017, Plant Crist replaced the Unit 7 flue gas monitors. During 2019, Plant Crist will replace CEMS monitors located in the scrubber stack.

Projections: Expenditures reflected in the 2019 projection filing for this line item total $200,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Substation Contamination Remediation
PEs 1007, 2859, 3400, 3412, 3463 and 3477

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
Three groundwater treatment systems were purchased for the treatment of contaminated groundwater at substation sites. Capital components of substation soil remediation projects are also included in the line.

Accomplishments:
Systems have proven effective in groundwater remediation. During 2014, additional groundwater recovery well pumps and controls were added to the existing Ft. Walton substation treatment system.

Project-to-Date: Plant-in-service of $4,979,829 projected at December 2019.

Progress Summary: During 2019, Gulf will be completing replacement of the groundwater remediation equipment at the Fort Walton substation and completing construction of the Wewa substation remediation system.

Projections: Expenditures reflected in the 2019 projection filing for this line item total $1,496,496.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Raw Water Flowmeters - Plants Crist and Smith
PEs 1155 and 1606

FPSC Approval: Order No. PSC-96-1171-FOF-EI

Description:
The Raw Water Flow Meters capital 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). These permits require the installation and monitoring of in-line totaling water flow meters on all existing and future water supply wells. Gulf incurred costs related to the installation and operation of new in-line totaling water flow meters at Plant Crist and Plant Smith for implementation of this new activity.

Accomplishments:
The raw water flow meters have been installed at Plant Crist and Plant Smith.

Project-to-Date: Plant-in-service of $149,950 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Cooling Tower Cell
PE 1232

FPSC Approval: Order No. PSC-94-0044-FOF-EI

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 to meet the National Pollution Discharge Elimination System (NPDES) industrial wastewater permit requirements.

Accomplishments:
Plant Crist has maintained compliance with the temperature discharge limits as required by the facility's NPDES Permit. The original cooling tower cell was retired during July 2007 when the new Crist Unit 7 cooling tower was placed-in-service in June 2007 as part of the Crist scrubber project that is reflected in Air Quality Compliance Program.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Dechlorination System
PEs 1180 and 1248

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
National Pollutant Discharge Elimination System 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.

Accomplishments:
During 2011-2012 Plant Crist replaced the existing sodium bisulfate storage tank and installed a new dechlorination system for the Unit 6 and Unit 7 cooling tower blowdowns and the ECUA return water pit. These systems are necessary in order to dechlorinate the industrial wastewater prior to discharge. The system has been effective in maintaining chlorine discharge limits.

Project-to-Date: Plant-in-service of $380,697 projected at December 2019.

Progress Summary: In service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Diesel Fuel Oil Remediation
PE 1270

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The Plant Crist diesel fuel oil remediation project included installing monitoring wells in the vicinity of the Crist diesel tank systems. The project also included the installation of an impervious cap to reduce migration of contaminants to groundwater.

Accomplishments: Monitoring wells and an impervious cap were installed.

Project-to-Date: Plant-in-service of $68,923 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Bulk Tanker Unloading Secondary Containment
PE 1271

FPSC Approval: Order No. PSC-94-1207-FOF-EI

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 required to be installed for tank unloading racks pursuant to the Federal Spill Prevention Control and Countermeasures (SPCC) regulation (40 CFR Part 112).

Accomplishments:
The Plant Crist unloading area secondary containment area complies with current SPCC regulatory requirements.

Project-to-Date: Plant-in-service of $101,495 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist IWW Sampling System
PE 1275

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The 1993 revision to Plant Crist's National Pollutant Discharge Elimination System (NPDES) industrial wastewater permit moved the 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 Industrial Wastewater (IWW) project also included a small building for monitoring and sampling equipment.

Accomplishments:
The dock is complete and samples are being collected at the required compliance point.

Project-to-Date: Plant-in-service of $59,543 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Sodium Injection System
PE 1214

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
The Sodium Injection System line item includes silo storage systems and associated components that 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 on Units 1 and 2 and is still in use at Plant Crist on Units 4 and 5. The injection of sodium carbonate as an additive to low sulfur coal reduces opacity levels to maintain compliance with the Clean Air Act provisions.

Accomplishments:
The silo storage and injection system components at Plant Crist have been installed and the system is fully operational. The Smith system was retired in April 2016 after the coal units ceased operations.

Project-to-Date: Plant-in-service of $284,622 projected at December 2019.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Stormwater Collection System
PE 1446

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The National Pollutant Discharge Elimination System (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.

Accomplishments:
The Plant Smith stormwater sump system has been effective in managing onsite stormwater.

Project-to-Date: Plant-in-service of $2,764,379 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Waste Water Treatment Facility
PEs 1466 and 1643

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
During the 1990's a domestic wastewater treatment facility was installed at Plant Smith to replace the septic tank system that was installed in the early 1960's. In April 2004 a new wastewater treatment facility with additional capacity was installed to replace the facility installed in the 1990's. The new treatment plant includes aeration and chlorination of the wastewater prior to discharge in the Plant Smith ash pond.

Accomplishments: Plant Smith has maintained compliance with the NPDES industrial wastewater permit.

Project-to-Date: Plant-in-service of $591,865 projected at December 2019.

Progress Summary: The current domestic wastewater treatment plant needs to be relocated as part of the Plant Smith ash pond closure project since the area will used for future dry ash stacking. Gulf plans to place the new wastewater treatment system in service in early 2019.

Projections: N/A.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Daniel Ash Management Project
PEs 1501, 1535, 1555 and 1819

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The original Daniel Ash Management project included the installation of a dry ash transport system, lining the bottom of the ash pond, closure and capping of the existing fly ash pond, and expansion of the landfill area. During 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.

Accomplishments: Construction of the new on-site ash storage facility was completed in 2006. Portions of the original Daniel ash storage facility were closed in place during 2010.

Project-to-Date: Plant-in-service of $14,950,124 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Water Conservation
PEs 1601

FPSC Approval: Order No. PSC-01-1788-FOF-EI and
Order No. PSC-09-0759-FOF-EI

Description:
Specific Condition nine of Plant Smith's consumptive use permit, issued by the Northwest Florida Water Management District (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. Phase II, the Smith Closed Loop Cooling System for the laboratory sampling system, was installed during 2005 to further reduce groundwater usage. Phase III includes investigating and installing a deep injection will system to allow Plant Smith to utilize reclaimed water.

As discussed in previous filings, Gulf has determined that it is feasible to inject reclaimed water into the Plant Smith deep injection well system. Gulf has installed three deep injection wells, piping, and initial equipment needed for the pump station.

Project-to-Date: Plant-in-service of $34,299,806 projected at December 2019.

Progress Summary: During the remainder of 2018 and 2019, Gulf will obtain additional operational data required to design the final pump station, wastewater treatment equipment, as well as additional piping and associated storage capacity. Gulf plans to begin construction of the reclaimed water pump station and wastewater treatment equipment during 2019.

Projections: The projected 2019 expenditures for this line item total $13,033,532.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Underground Fuel Tank Replacement
PE 4397

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Underground Fuel Tank Replacement Program provided for the replacement of Gulf's underground storage tanks with new above ground tanks (ASTs). The installation of ASTs significantly reduced the risk of potential petroleum product discharges, groundwater contamination, and subsequent remediation activities.

Accomplishments:
All underground storage tanks have been replaced with above ground tank systems.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist FDEP Agreement for Ozone Attainment
PEs 1031, 1158, 1167, 1199, 1250, 1258, 1287 and 1958

FPSC Approval: Order No. PSC-02-1396-FOF-EI

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 Units 4 and 5 if necessary, to meet the NO_x standard specified in the Agreement.

Accomplishments: The new Crist Unit 7 precipitator and SCR were placed in service during 2004 and 2005, respectively. The Crist Unit 6 Selective Non-Catalytic Reduction (SNCR)/low NOx burners with Over-Fired Air (OFA) technologies were then placed in service during November 2005. The Crist Unit 4 and Unit 5 SNCRs were subsequently placed in service during April 2006. The Crist Unit 6 SNCR was retired during the Spring of 2012 when the Crist Unit 6 SCR was placed in-service. Gulf replaced one layer of the Plant Crist Unit 7 SCR catalyst during the Fall of 2014. Gulf replaced the Plant Crist Unit 7 SCR ammonia unloading piping during 2015 and upgraded the digital control system for the Unit 7 SCR. Gulf replaced a layer of the Plant Crist unit 7 SCR catalyst and installed the Plant Crist unit 6 flame scanner during 2016. Gulf replaced the Crist Unit 7 Fgas fans, a layer of the Plant Crist unit 7 SCR catalyst, and performed work on the Unit 7 SCR during 2018.

Project-to-Date: Plant-in-service of $122,186,973 projected at December 2019.

Progress Summary: During 2019, Gulf will be making a progress payment for the catalyst on Crist Unit 7 being replaced during the 2020 outage.

Projections: The projected 2019 expenditures for this line item total $200,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SPCC Compliance
PEs 1272, 1404, 1628 and 4418

FPSC Approval: Order No. PSC-03-1348-FOF-EI

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 being classified as bulk storage containers that are subject to the secondary containment requirements in 40 CFR Part 112.8(c).

Accomplishments: The 2006 SPCC project at Plant Crist routed stormwater from the switchyard drains to the new oil skimming sump where any potential spill could be captured, preventing the oil from reaching surface water. During 2009, Plant Smith installed secondary containment for a padmount transformer located along the ash pond discharge canal. During 2012, Plant Smith installed a secondary containment system for the diesel emergency sump pump system. During 2017, Gulf installed a double walled fuel tank at the Panama City Beach Facility for the emergency generator.

Project-to-Date: Plant-in-service of $947,925 projected at December 2019.

Progress Summary: In-service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Common FTIR Monitor
PE 1297

FPSC Approval: Order No. PSC-03-1348-FOF-EI

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.

Accomplishments: Purchasing the FTIR instrument has enabled Gulf Power to measure ammonia slip emissions as required by the Plant Crist air permit.

Project-to-Date: Plant-in-service of $62,870 projected at December 2019.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Precipitator Upgrades for Compliance Assurance Monitoring Compliance PEs 1175, 1191, 1305 and 1330

FPSC Approval: Order No. PSC-04-1187-FOF-EI

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 timeframe. CAM requirements are regulated under Title V of the 1990 Clean Air Act Amendments (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.

Accomplishments: The Plant Smith Unit 2 and Unit 1 precipitator upgrades were placed in service during April 2005 and May 2007, respectively. The Plant Scholz Unit 2 precipitator upgrade was completed during December of 2007. The Plant Crist Units 4 and 5 precipitator upgrades were placed in-service during March of 2008. The Scholz precipitators were retired in 2015. The Plant Smith precipitators were retired in April 2016 after the Plant Smith Units 1 & 2 ceased operations.

Project-to-Date: Plant-in-service of $13,997,696 projected at December 2019.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant Groundwater Investigation
PEs 1218 and 1361

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The Florida Department of Environmental Protection (FDEP) lowered the arsenic groundwater standard from 0.05 mg/L to 0.01 mg/L effective January 1, 2005. Historical groundwater monitoring data from Plants Crist and Scholz indicated that these facilities may be unable to comply with the lower standard.

Accomplishments: The Plant Crist and Plant Scholz projects have been canceled because Gulf has been released from any arsenic remedial actions at these sites.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Water Conservation Project
PEs 1178, 1227 and 1298

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description:
This project is part of the Plant Crist water conservation and consumptive use efficiency program to reduce the demand for groundwater and surface water withdrawals. Specific Condition six of the Northwest Florida Water Management District Individual Water Use Permit Number 19850074 issued January 27, 2005 requires Plant Crist to implement measures to increase water conservation and efficiency at the facility. The first Plant Crist Water Conservation project was placed in service during 2006. This project included installing automatic level controls on the fire water tanks to reduce groundwater usage. The second phase of the project involves utilizing reclaimed water from ECUA's wastewater treatment plant to reduce the demand for groundwater and surface water withdrawals at Plant Crist. The Northwest Florida Water Management District has agreed that this is a valid project to pursue for continued implementation of the water conservation effort.

Accomplishments: Level controls were installed on the fire tank system during 2006. Portions of the Plant Crist reclaimed water project were placed in-service in 2009 and 2010. Gulf began receiving reclaimed water from ECUA in November 2010. During the 2011-2012 timeframe, Gulf installed defoaming and acid injection systems for the Units 6-7 cooling towers to treat scaling and foam associated with reclaimed water usage. During 2017, Gulf replaced two header pumps that were installed when Plant Crist began receiving reclaimed water. In 2018, Gulf's plan is to replace the remaining three header pumps.

Project-to-Date: Plant-in-service of $20,195,681 projected at December 2019.

Progress Summary: During 2019, Gulf plans on replacing pumps, piping, valves and motors that were installed when Plant Crist began receiving reclaimed water.

Projections: The projected 2019 expenditures for this line item total $100,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant NPDES Permit Compliance Projects
PEs 0433, 1204 and 1299

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The water quality based copper effluent limitations included in Chapter 62 Part 302, Florida Administrative Code (F.A.C.) were amended in April 2002 with an effective date of May 2002. The more stringent hardness based standard is included by reference in the Plant Crist National Pollutant Discharge Elimination System (NPDES) industrial wastewater permit.

Accomplishments: Plant Crist installed stainless steel condenser tubes on Unit 6 during June 2006 in an effort to meet the revised water quality standards during times of lower hardness in the river water. During 2008, Plant Crist completed the second phase of the project which involved installing a chemical treatment system in the ash pond. During 2010, Gulf completed the third phase of the project that included installing an aeration system in the ash pond. During 2011-2012, Plant Crist completed installation of a new caustic tank and a sulfuric acid tank as part of the ash pond chemical treatment system.

During 2018, Plant Smith will complete 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 industrial wastewater permit.

Project-to-Date: Plant-in-service of $6,167,068 projected at December 2019.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Air Quality Compliance Program
PEs 0560, 0860,1034, 1035, 1036, 1037, 1067, 1095, 1168, 1188, 1222, 1233, 1279, 1288, 1362, 1505, 1508, 1512, 1513, 1517, 1551, 1552, 1646, 1684, 1701, 1727, 1728, 1729, 1768, 1774, 1778, 1791, 1798, 1809, 1810, 1824, 1826, 1909, 1911, 1913 and 1950

FPSC Approval: Order No. PSC-06-0972-FOF-EI

Description: This line item covers the prudently incurred costs for compliance with Gulf's Air Quality Compliance Program including the expenses associated with Gulf's ownership portion of the Scherer 3 baghouse, SCR, and scrubber projects and associated equipment.

Accomplishments: The Plant Smith Unit 1 and Unit 2 SNCRs were placed in service during May 2009 and December 2008, respectively. The Plant Smith SNCRs were retired in April 2016 after Plant Smith Units 1 & 2 ceased operations. The Crist Units 4 - 7 scrubber project was placed in-service in December of 2009 and the Crist Unit 6 hydrated lime injection system was placed in-service in 2011. The Plant Crist Unit 6 SCR was placed-in-service in April of 2012. The Plant Daniel scrubber projects were placed in-service in November 2015. Plant Daniel's bromine and activated carbon injection systems were placed in-service in December 2015. The scrubbers when used in conjunction with the bromine and activated carbon injection systems will allow Plant Daniel to comply with the MATS standards. Plant Scherer 3 baghouse was placed in-service February 2009, SCR in-service December 2010, and scrubber in-service March 2011.

Project-to-Date: Plant-in-service of $1,360,480,617 projected at December 2019.

Progress Summary: During 2019, the Air Quality Compliance program includes costs associated with the following: Plant Crist and Plant Daniel scrubbers, Plant Crist Unit 6 SCR, as well as the Plant Daniel Low NOx burners. More specifically, it includes expenditures for the Plant Crist gypsum storage area, gas cooling nozzles, scrubber agitator gear box, Unit 6 SCR catalyst layer, elevator, and air compressors. Approximately $6.2 million is projected for expansion of the Plant Crist UIC pump station. The expansion will allow Plant Crist to utilize two additional wells for disposal of wastewater generated from the gypsum storage facility and associated groundwater remediation system. Plant Crist will also be constructing a new limestone system that will add limestone as needed to the coal to help maintain the performance of catalyst used in the SCRs. The cost of the new limestone system is projected to be approximately $1

million. During 2019, Gulf will be making a progress payment of $500,000 for a new scrubber alignment grid at Plant Crist that will be installed in the 2020 scrubber outage. Plant Daniel will also be replacing the low NOx burners on Unit 2, which have reached the end of their useful life. The cost of the new low NOx burners is approximately $490,000.

Projections: The total projected 2019 expenditures for this line item total $8,660,145.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: General Water Quality
PEs 0831, 0861 and 1280

FPSC Approval: Order No. PSC-06-0972-FOF-EI

Description: The General Water Quality line item includes capital expenditures required to ensure compliance with Gulf Power's NPDES industrial wastewater permits. Gulf purchased a boat during 2007 for surface water sampling required by the Plants Crist, Smith and Scholz National Pollutant Discharge Elimination System (NPDES) permits. The permits had new conditions which required Gulf to establish a biological evaluation plan and implementation schedule for each plant.

Accomplishments: The General Water Quality sampling boat was purchased during 2007. It is currently being used to conduct Gulf's surface water sampling for Plants Crist, Smith, and Scholz. Plant Crist installed additional groundwater monitoring wells during 2017 and plans to install additional wells in 2018 for compliance with the plant's NPDES industrial wastewater permit.

Project-to-Date: Plant-in-service of $832,922 projected at December 2019.

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Coal Combustion Residuals
PEs 0404, 0412, 0424, 0514, 1597, 1598, 1599, 1641, 1997, 4405, 4430, 4440, 6756, 6757, 6759, 6764 and 6765

FPSC Approval: PSC-15-0536-FOF-EI

Description: The Coal Combustion Residuals (CCR) program includes expenses related to the regulation of Coal Combustion Residuals by the United States Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("FDEP"). On April 17, 2015 EPA published the final CCR rule in the Federal register regulating CCR disposal under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The CCR rule is located in Title 40 Code of Federal Regulations (CFR) Parts 257 and 261. The CCR rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste at active generating power plants. 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, which requires permit applications to be submitted for the facility's ash pond and CCR landfill by November 22, 2019.

Accomplishments: Gulf installed additional groundwater monitoring wells at Plants Crist, Daniel, and Smith during 2015. In 2017, Gulf completed construction of a slurry wall and new industrial wastewater treatment pond at Scholz. Construction activities for the ash pond closures at Plant Scholz and Plant Smith began in 2018.

Project-to-Date: Plant-in-service of $41,778,858 projected at December 2019.

Progress Summary: During 2019, the Scholz ash pond closure project will include construction of a new stormwater management system, transferring CCR material to a dry stack area within the footprint of the pond, and capping the dry stack area with closure turf material. At Plant Smith, Gulf will proceed with construction of new industrial wastewater ponds and a slurry wall as well as transferring CCR material to a dry stack area within the footprint of the pond during 2019.

Engineering and construction of the Scherer dry ash handling system is expected to be completed in 2019 and design and construction of the CCR wastewater management system will continue in 2019. In addition, detailed engineering and construction will continue on Cell 3 of the onsite landfill for CCR storage. Plant Scherer will also proceed with siting studies and preliminary design for a new landfill.

Final design and initial construction of a new wastewater treatment and bottom ash handling system will occur at Plant Daniel during 2019. Plant Daniel will need to reroute wastewater streams from the ash pond to a new wastewater system prior to beginning closure of the bottom ash pond in 2021. Plant Daniel is currently in the process of completing studies to determine the most cost-effective technologies and system design.

Projections: The total projected 2019 expenditures for this line item total $50,765,515.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Steam Electric Power Effluent Limitations Guidelines and Standards
PEs 1193, 1912 and 6754

FPSC Approval: PSC-15-0536-FOF-EI

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.

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 propose ELG rule revisions in December 2018 and to finalize the rulemaking in 2019.

Project-to-Date: Plant-in-service of $5,655,259 projected at December 2019.

Progress Summary: Gulf has projected expenditures in 2019 for engineering and design of Gulf's ownership portion of the Scherer scrubber wastewater treatment system.

Projections: The projected 2019 expenditures for this line item total $456,695.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: 316(b) Cooling Water Intake Structure Regulation
PE 1691

FPSC Approval: Order No.

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, (See Exhibit RMM-1), 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 and National Marine Fisheries Service (Services) and EPA, Gulf Power's preliminary studies indicate Plant Smith will need to install new lower capacity intake pumps and a closed-cycle cooling tower monitoring system for the existing Unit 3 closed-cycle cooling tower.

Accomplishments: N/A

Project-to-Date: Plant-in-service of $2,000,000 projected at December 2019.

Progress Summary: Gulf plans to install new lower capacity intake pumps at Plant Smith during 2019. The Plant Smith industrial wastewater permit requires Gulf to submit information required under the Cooling Water Intake Structure 316(b) rule with its next permit renewal that is due in April of 2019 for FDEP review and approval.

Projections: The total projected 2019 expenditures for this line item total $2,000,000.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Mercury Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Mercury Allowances were included as part of Gulf's March 2007 CAIR/CAMR/CAVR Compliance Program. The purchase of allowances in conjunction with the retrofit projects comprised the most reasonable, cost-effective means for Gulf to meet the CAIR, CAMR and CAVR requirements. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion vacating EPA's CAMR. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements. In response to the CAMR vacatur, mercury allowances have been removed from Gulf's Air Quality Compliance Program.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Annual NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Although the retrofit installations set forth in Gulf's Air Quality Compliance Program significantly reduce emissions, they 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.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:
Gulf began surrendering annual NOx allowances during 2009.

Projections: The projected 2019 O&M Annual NOx allowance expenses are $7,214.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Seasonal NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Although the retrofit installations set forth in Gulf's Air Quality Compliance Program significantly reduce emissions, the projects would not result in Gulf achieving CAIR/CASPR 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/CSAPR requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:
Gulf began surrendering seasonal NOx allowances during 2009.

Projections: The projected 2019 O&M Seasonal NOx allowance expenses are $7,887.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SO_2 Allowances

FPSC Approval: Order No. PSC-94-0044-FOF-EI

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.

Accomplishments: Gulf executed forward contacts to secure allowances during 2006, 2007, and 2009.

Project-to-Date: N/A

Progress Summary: See Accomplishments

Projections: The projected 2019 O&M SO_2 allowance expenses are $37,762.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.1

Title: Sulfur

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Plant Crist Unit 7 sulfur trioxide (SO_3) flue gas system allowed for the injection of SO_3 into the flue gas stream. The addition of sulfur trioxide to the flue gas improved the collection efficiency of the precipitator when burning a low sulfur coal. Sulfur trioxide agglomerated the particles which in turn enhanced the collection efficiency of the precipitator.

Accomplishments:
The flue gas injection system was retired during 2005.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.2

Title: Air Emission Fees

FPSC Approval: Order No. PSC-94-0044-FOF-EI

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 Clean Air Act Amendments.

Accomplishments:
Fees have been paid by due dates.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $305,099

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.3

Title: Title V

FPSC Approval: Order No. PSC-95-0384-FOF-EI

Description:
Title V expenses are associated with preparation of the Clean Air Act Amendments (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. 2014, 2019, etc). Title V permits are periodically revised between renewals to incorporate major changes or modifications of a source.

Accomplishments:
Gulf's Title V permit renewals were finalized in January 2015 and are valid for a 5-year period. Title V permit amendments to incorporate a new Southern System NOx Averaging Plan for the Acid Rain Program (Title IV Permits) were issued by FDEP during July 2016 for Plant Crist, Plant Scholz and Plant Smith. Gulf's Perdido Landfill Gas-to-Energy Facility Title V permit was issued on November 16, 2016 and is valid for a 5-year period.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $293,254

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.4

Title: Asbestos Fees

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
Asbestos Fees include both annual and individual project fees due to the Florida Department of Environmental Protection (FDEP) for asbestos abatement projects.

Accomplishments:
Fees are paid as required by FDEP.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.5

Title: Emission Monitoring

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Emission Monitoring program provides quality assurance/quality control testing for Continuous Emission Monitoring systems, including Relative Accuracy Test Audits and Linearity Tests, as required by the Clean Air Act Amendments (CAAA) of 1990.

Accomplishments:
All systems are in compliance.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $739,036

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.6

Title: General Water Quality

FPSC Approval: **Order No. PSC-94-0044-FOF-EI**
Order No. PSC-04-1187-FOF-EI
Order No. PSC-08-0775-FOF-EI
Order No. PSC-11-0553-FOF-EI

Description:
The General Water Quality program includes activities undertaken pursuant to the Company's NPDES industrial wastewater permit including dechlorination, surface and groundwater monitoring studies and associated assessment activities, and soil contamination studies. This line item also includes expenses for Gulf's Cooling Water Intake program, the Impaired Waters Rule, Storm Water Maintenance, and the Impoundment Integrity project.

Accomplishments:
All activities are on-going in compliance with applicable environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $2,014,654.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.7

Title: Groundwater Contamination Investigation

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Groundwater Contamination Investigation project includes sampling and testing to determine possible environmental impacts to soil and groundwater from past herbicide applications at various substation sites. Once possible environmental impacts to groundwater and soils have been identified cleanup operations are initiated.

Accomplishments:
The Florida Department of Environmental Protection has issued a No Further Action (NFA) letter or Site Rehabilitation Completion Order for 95 sites.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $2,825,274

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.8

Title: State NPDES Administration

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The State NPDES Administration fees are required by the State of Florida's National Pollutant Discharge Elimination System (NPDES) program administration. Annual and five-year permit renewal fees are required for the NPDES industrial wastewater permits at Plants Crist, Smith and Scholz.

Accomplishments:
Gulf has complied with the NPDES program administration fee submittal schedule.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $42,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.9

Title: Lead & Copper Rule

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The Lead and Copper Rule expenses include potable water treatment and sampling costs as required by the Florida Department of Environmental Protection (FDEP) regulations.

Accomplishments:
Gulf has complied with all sampling and analytical protocols.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $4,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.10

Title: Environmental Auditing/Assessment

FPSC Approval: Order No. PSC-94-0044-FOF-EI

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.

Accomplishments:
Audits and assessments completed to date have demonstrated compliance with environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $15,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.11

Title: General Solid and Hazardous Waste

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The General Solid and Hazardous Waste program provides for the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes. This line item also includes O&M expenses associated with Gulf's Spill Prevention Control and Countermeasures (SPCC) plans.

Accomplishments:
Gulf has complied with all hazardous and solid waste regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: **$**1,000,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.12

Title: Above Ground Storage Tanks

FPSC Approval: Order No. PSC-97-1047-FOF-EI

Description:
The aboveground storage tank projects are required under the provisions of 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.

Accomplishments:
Gulf has complied with all applicable storage tank requirements.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $92,532

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.13

Title: Low NO_x

FPSC Approval: Order No. PSC-98-0803-FOF-EI

Description:
The Low NO_x activity refers to the maintenance expenses associated with the Low NO_x burner tips on Crist Units 4 & 5 and Smith Unit 1.

Accomplishments:
Burner tips were installed on Plant Crist Units 4 & 5 and Plant Smith Unit 1. The Plant Smith Unit 1 Low NOx burners were retired in April 2016 when the unit ceased operations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.14

Title: Ash Pond Diversion Curtains

FPSC Approval: Order No. PSC-98-1764-FOF-EI

Description:
The installation of flow diversion curtains in the Plant Crist industrial wastewater pond were required to effectively increase water retention time in the pond. Diversion curtains allow for the sedimentation/precipitation treatment process to be more effective in reducing levels of suspended particulate from the Plant Crist outfall.

Accomplishments:
Plant Crist replaced the diversion curtains and dredged the pond during the 2009-2010 timeframe.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.15

Title: Mercury Emissions

FPSC Approval: Order No. PSC-99-0912-FOF-EI

Description: The Mercury Emissions program pertains to requirements for Gulf to periodically analyze coal shipments for mercury and chlorine content. The Environmental Protection Agency (EPA) mandated that shipments of coal would be analyzed for mercury and chlorine only during 1999. No further notices of continued sampling requirements of coal shipments beyond 1999 have been issued by EPA, therefore, no expenses have been planned for this activity.

Accomplishments:
Coal shipments were analyzed as required during 1999. Sampling and analytical requirements are not expected during 2019.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.16

Title: Sodium Injection

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
This line item includes O&M expenses associated with the sodium injection system at Plant Crist. Sodium carbonate is added to the Plant Crist coal supply to enhance precipitator efficiencies when burning certain low sulfur coals.

Accomplishments:
Sodium carbonate injection is used at Plant Crist as necessary when low sulfur coal is burned.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $10,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.17

Title: Gulf Coast Ozone Study (GCOS)

FPSC Approval: Order No. PSC-00-0476-FOF-EI

Description:
This project referred to Gulf's participation in the Gulf Coast Ozone Study (GCOS) which was a joint modeling analysis between Gulf Power and the State of Florida to provide an improved basis for assessment of eight-hour ozone air quality for Northwest Florida. The goal of the project was to develop strategies for ozone ambient air attainment to supplement the Florida Department of Environmental Protection (FDEP) studies submitted to the Environmental Protection Agency (EPA) for Escambia and Santa Rosa counties.

Accomplishments: The GCOS project was completed during 2006.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.18

Title: SPCC Substation Project

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
During 2002 EPA published a revision to Title 40 Code of Regulation Part 112, commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. The revision expanded applicability of the rule to specifically include oil containing electrical transformers and regulators. Gulf was required to install additional containment and/or diversionary structures or equipment at several substations to prevent a potential discharge of oil to navigable waters of the United States or adjoining shorelines.

Accomplishments: Gulf has assessed its substations to determine which sites are subject to the revised SPCC regulations. Additional containment has been added to the substations that were identified as having a higher risk of discharging oil into navigable waters of the United States or adjoining shorelines.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.19

Title: FDEP NO_x Reduction Agreement

FPSC Approval: Order No. PSC-02-1396-FOF-EI

Description: This line item includes O&M expenses associated with the Crist Unit 7 SCR and the Crist Units 4 and 5 Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the Florida Department of Environmental Protection (FDEP) and Gulf Power Agreement entered into on August 28, 2002 to address ozone attainment. Anhydrous ammonia, urea, air monitoring, catalyst regeneration, and general operation and maintenance expenses are included in this line item.

Accomplishments: The Crist Unit 7 SCR and the Crist Units 4 and 5 SNCRs are fully operational. The Crist Unit 6 SNCR was retired when the Crist Unit 6 SCR was placed in-service during the Spring of 2012. The Crist Unit 6 SCR was installed as part of the Air Quality Compliance Program.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,021,274

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.20

Title: Air Quality Compliance Program

FPSC Approval: **Order No. PSC-06-0972-FOF-EI**
Order No. PSC-13-0506-PAA-EI
Order No. PSC-17-0178-S-EI

Description: This line item covers prudently incurred costs for compliance with Gulf's Air Quality Compliance Program including expenses associated with Gulf's ownership portion of the Scherer 3 baghouse, SCR, and scrubber projects as well as associated equipment. More specifically, the line item includes the cost of anhydrous ammonia, hydrated lime, urea, limestone and general O&M expenses.

Accomplishments: The Plant Smith Unit 1 and Unit 2 SNCRs were placed in service during May 2009 and December 2008, respectively. The Smith SNCRs were retired in April 2016 after the coal units ceased operations. The Crist Units 4 -7 scrubber project was placed in-service December of 2009 and the Crist Unit 6 hydrated lime injection system was placed in-service in 2011. The Plant Crist Unit 6 SCR was placed-in-service in April of 2012. The Plant Daniel scrubbers were placed in-service in November 2015. The Plant Daniel Bromine and Activated Carbon Injection systems were placed in-service in December 2015. This line items includes expenses associated with a baghouse, SCR, and scrubber as well as associated equipment installed at Plant Scherer 3. Plant Scherer 3 baghouse was placed in-service February 2009, SCR in-service December 2010, and scrubber in-service March 2011.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: **$**21,813,790

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.21

Title: Maximum Achievable Control Technology (MACT)
Information Collection Request (ICR)

FPSC Approval: Order No. PSC-09-0759-FOF-EI

Description: During early 2010 EPA finalized an extensive Information Collection Request (ICR) for coal and oil fired steam electric generating units to support Maximum Achievable Control Technology (MACT) rulemaking under Section 112 of the Clean Air Act (CAA). The ICR required submission of information on control equipment efficiencies, emissions, capital and O&M costs, and fuel data for all coal and oil fired generating units greater than 25 MW.

Accomplishments:
Gulf completed the Part I & 2 MACT ICR survey and the Part 3 emissions testing reports during 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.22

Title: Crist Water Conservation

FPSC Approval: Order No. PSC-08-0775-FOF-EI

Description: Gulf Power entered into an agreement with the Emerald Coast Utilities Authority (ECUA) to begin utilizing reclaimed water to reduce the demand for groundwater and surface water withdrawals. This line item includes general O&M expenses associated with the Plant Crist reclaimed water system such as piping, pump, and valve maintenances.

Accomplishments:
Gulf began receiving reclaimed water from ECUA during November 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $428,542

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2019 - December 2019

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.23

Title: Coal Combustion Residuals

FPSC Approval: PSC-15-0536-FOF-EI

Description: The Coal Combustion Residuals (CCR) program includes expenses related to the regulation of Coal Combustion Residuals by the United States Environmental Protection Agency ("EPA") and the Florida Department of Environmental Protection ("FDEP"). On April 17, 2015 EPA published the final CCR rule in the Federal register regulating CCR disposal under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The CCR rule is located in Title 40 Code of Federal Regulations (CFR) Parts 257 and 261. The CCR rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste at active generating power plants. 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, which requires permit applications to be submitted for the facility's ash pond and CCR landfill by November 22, 2019.

In addition, pursuant to its authority granted under the Clean Water Act, the FDEP issues National Pollutant Discharge Elimination System (NPDES) industrial wastewater permits for each of Gulf's generating facilities. A NPDES permit renewal for Plant Scholz (FL0002283) was issued on October 20, 2015 which requires closure of the existing on-site ash pond during the 2015-2020 permit cycle.

Accomplishments:
During 2015 Gulf established a publicly available website, began conducting and documenting weekly and monthly inspections, and prepared a fugitive dust plan as required by the CCR rule. Gulf also installed permanent markers at all CCR ponds and conducted annual inspections of the CCR impoundments and landfills. In 2017, Gulf completed construction of the Plant Scholz slurry wall, industrial wastewater pond, and supporting activities to facilitate closure. In 2018, Gulf moved forward with the Smith and Scholz ash pond closure projects which includes removing CCR material from portions of the existing ponds, and transferring CCR material to a dry stack area within the footprint of the pond.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $3,229,639.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
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Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.24

Title: Smith Water Conservation

FPSC Approval: Order No. PSC-09-0759-FOF-EI

Description: Specific Condition Nine of the Northwest Florida Water Management District (NFWMD) Individual Water Use Permit Number 19850773 (Permit) issued on November 30, 2006, requires Gulf's Plant Smith to implement measures to increase water conservation and efficiency. On October 20, 2008, the NWFMD issued a letter stating that the re-use of reclaimed water meets the requirement listed in Specific Condition Nine in the Permit. This line item includes general O&M expenses associated with the Plant Smith reclaimed water system such as sampling and analytical charges, and mechanical integrity testing expenses required by the FDEP permit.

Fiscal Expenditures: N/A

Progress Summary: Gulf has installed three deep injection wells, a pump station and associated piping

Projections: $190,000

AUTHENTICATED U.S. GOVERNMENT INFORMATION GPO



FEDERAL REGISTER

Vol. 79 Friday,
No. 158 August 15, 2014

Part II

Environmental Protection Agency

40 CFR Parts 122 and 125
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; Final Rule

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 35
PARTY: GULF POWER COMPANY (GULF) (DIRECT)
DESCRIPTION: Richard M. Markey RMM-2

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 122 and 125

[EPA–HQ–OW–2008–0667, FRL–9817–3]

RIN 2040–AE95

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The purpose of this action is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures used by certain existing power generation and manufacturing facilities for the withdrawal of cooling water from waters of the United States. This rule establishes requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities and existing manufacturing and industrial facilities that are designed to withdraw more than 2 million gallons per day (mgd) of water from waters of the United States and use at least 25 percent of the water they withdraw exclusively for cooling purposes. These national requirements, which will be implemented through National Pollutant Discharge Elimination System (NPDES) permits, apply to the location, design, construction, and capacity of cooling water intake structures (CWIS) at regulated facilities and provide requirements that reflect the best technology available (BTA) for minimizing adverse environmental impact. On April 20, 2011, EPA published a proposed rule that included several options for addressing these impacts. Subsequently, EPA published two Notices of Data Availability (NODA), on June 11, 2012 and June 12, 2012, that further clarified EPA's proposed approach. This final rule also responds to judicial remand of aspects of the previously promulgated Phase II and Phase III section 316(b) rules. In addition, EPA is also responding to an earlier judicial decision by removing from the previously promulgated Phase I new facility rule a restoration-based compliance alternative and the associated monitoring and demonstration requirements.

DATES: This regulation is effective October 14, 2014. For judicial review purposes, this final rule is promulgated as of 1 p.m. EDT (Eastern Daylight Time) on August 29, 2014 as provided in 40 CFR 23.2.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OW–2008–0667. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., CBI (confidential business information) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hardcopy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hardcopy at the Water Docket in the EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is 202–566–1744, and the telephone number for the Water Docket is 202–566–2426.

FOR FURTHER INFORMATION CONTACT: For additional biological information, contact Tom Born at 202–566–1001; email: *born.tom@epa.gov*. For additional economic information, contact Wendy Hoffman at 202–564–8794; email: *hoffman.wendy@epa.gov*. For additional technical information, contact Paul Shriner at 202–566–1076; email: *shriner.paul@epa.gov*.

SUPPLEMENTARY INFORMATION:

What facilities are regulated by this action?

This final rule applies to existing facilities that use cooling water intake structures to withdraw water from waters of the United States and have or require an NPDES (National Pollutant Discharge Elimination System) permit issued under section 402 of the CWA (Clean Water Act). Existing facilities subject to this regulation include those with a design intake flow (DIF) greater than 2 mgd. If a facility meets these conditions, it is subject to today's final regulations. If a facility has or requires an NPDES permit but does not meet the 2 mgd intake flow threshold, it is subject to permit conditions implementing CWA section 316(b), developed by the NPDES Permit Director on a case-by-case basis using BPJ (best professional judgment) under 40 CFR 125.90(b). This final rule defines the term *cooling water intake structure* to mean the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the United States. The cooling water intake structure extends from the point at which water is first withdrawn from waters of the United States source up to, and including, the intake pumps. Generally, facilities that meet these criteria fall into two major groups: steam electric generating facilities and manufacturing facilities. The final rule also makes limited changes to the requirements for Phase I facilities (i.e., new facilities).

Exhibit 1 lists industry sectors of facilities subject to this final rule. This table is not intended to be exhaustive; facilities in other industries not listed in Exhibit 1 could also be regulated. The 4-digit NAICS industry sectors may include 6-digit NAICS industry sub-sectors with operations that are not dependent on cooling water.

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EXHIBIT 1—INDUSTRY SECTORS WITH FACILITIES SUBJECT TO THE FINAL RULE

Category	4-Digit NAICS industry sectors	NAICS definition
Federal, State and Local Government	Electric Power Industry	
	2211	Electric Power Generation, Transmission and Distribution.
Industry	Electric Power Industry	
	2211	Electric Power Generation, Transmission and Distribution.
Industry	Primary Manufacturing Industries	
	3112	Grain and Oilseed Milling.
	3113	Sugar and Confectionery Product Manufacturing.
	3121	Beverage Manufacturing.
	3221	Pulp, Paper, and Paperboard Mills.
	3222	Converted Paper Product Manufacturing.
	3241	Petroleum and Coal Products Manufacturing.
	3251	Basic Chemical Manufacturing.
	3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments Manufacturing.
	3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing.
	3254	Pharmaceutical and Medicine Manufacturing.
	3256	Soap, Cleaning Compound, and Toilet Preparation Manufacturing.
	3259	Other Chemical Product and Preparation Manufacturing.
	3311	Iron and Steel Mills and Ferroalloy Manufacturing.
	3312	Steel Product Manufacturing from Purchased Steel.
	3313	Alumina and Aluminum Production and Processing.
Industry	Other Industries	
	1119	Other Crop Farming.
	2122	Metal Ore Mining.
	3133	Textile and Fabric Finishing and Fabric Coating Mills.
	3211	Sawmills and Wood Preservation.
	3314	Nonferrous Metal (except Aluminum) Production and Processing.
	3322	Cutlery and Handtool Manufacturing.
	3329	Other Fabricated Metal Product Manufacturing.
	3364	Aerospace Product and Parts Manufacturing.
	3391	Medical Equipment and Supplies Manufacturing.

To determine whether a facility could be regulated by this action, one should carefully examine the applicability criteria in § 125.91 of the final rule. For information regarding the applicability of this action to an entity, consult the persons listed for technical information in **FOR FURTHER INFORMATION CONTACT**.

Supporting Documentation

1. Docket

EPA has established an official public docket for this action under Docket ID EPA–HQ–OW–2008–0667. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include information claimed as Confidential Business Information (CBI) or other information, the disclosure of which, is restricted by statute. For information on how to access materials in the docket, see **ADDRESSES** above. To view docket materials, call ahead to schedule an appointment. Every user is entitled to copy 266 pages per day before incurring a charge. The Docket Center may charge $0.15 for each page over the 266-page limit, plus an administrative fee of $25.00.

2. Electronic Access

You may access this **Federal Register** document and the docket electronically through the Web site *http://www.regulations.gov* by searching for Docket ID EPA–HQ–OW–2008–0667. For additional information about the public docket, visit the EPA Docket Center home page at *http://www.epa.gov/epahome/dockets.htm*.

3. Technical Support Documents

The final regulation is supported by three major documents:

- Economic Analysis for the Final Section 316(b) Existing Facilities Rule (EPA–821–R–14–001), referred to as the EA throughout. This document presents the analysis of compliance costs, economic impacts, energy supply effects, and a summary of benefits associated with the final rule.
- Benefits Analysis for the Final Section 316(b) Existing Facilities Rule (EPA–821–R–14–005), referred to as the BA throughout. This document examines cooling water intake structure impacts and regulatory benefits at the regional and national levels.
- Technical Development Document for the Final Section 316(b) Existing Facilities Rule (EPA–821–R–14–002), referred to as the TDD throughout. This document presents detailed information on the methods used to develop unit costs and describes the set of technologies that may be used to meet the final rule requirements.

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I. Executive Summary and Scope of Today's Rulemaking

A. Executive Summary

1. Summary of the Major Provisions of the Regulatory Action

This rule establishes requirements under section 316(b) of the Clean Water Act (CWA) for existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day (mgd) of water from waters of the United States and use at least 25 percent of the water they withdraw exclusively for cooling purposes. These national requirements, which will be implemented through National Pollutant Discharge Elimination System (NPDES) permits, apply to the location, design, construction, and capacity of cooling water intake structures (CWIS) at regulated facilities by setting requirements that reflect the best technology available (BTA) for minimizing adverse environmental impact.[1] On April 20, 2011, EPA published a proposed rule that included several options for addressing these impacts. EPA published two Notices of Data Availability (NODA), on June 11, 2012 and June 12, 2012, that further clarified EPA's approach. This final rule constitutes EPA's response to the remand of the Phase II and Phase III rules. In addition, EPA is also responding to the decision in *Riverkeeper I* to remove from the Phase I new facility rule the restoration-based compliance alternative and the associated monitoring and demonstration requirements.

2. Need for the Rule

Cooling water is withdrawn for the purpose of dissipating waste heat from industrial processes. Over half of all water withdrawn in the United States each year is for cooling purposes. By far, the largest industrial use of cooling water is for thermoelectric generation, but cooling water is also used in the manufacture of aluminum, chemicals and allied products, food and kindred products, pulp and paper, refined petroleum products, and steel, as well as in other industries. Although newer designs are more efficient, the long life of the capital equipment in these industries suggests that the adverse environmental impacts could continue for decades. Electric generators, for

[1] As noted here, the term BTA means ''best technology available for minimizing adverse environmental impact.'' In the interests of brevity, the acronym will frequently be used in the preamble to reflect the entire definition.

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example, typically convert 30 to 40 percent of the heat content of their fuel to electricity, depending on their fuel source, age of their facility, and capacity utilization (see TDD 5.1). The purpose of cooling water withdrawals is to dissipate that portion of the heat that is a by-product of industrial processes that facilities have not used and therefore view as waste heat.

The withdrawal of cooling water by existing facilities removes and kills hundreds of billions of aquatic organisms from waters of the United States each year, including plankton (small aquatic animals, including fish eggs and larvae), fish, crustaceans, shellfish, sea turtles, marine mammals, and many other forms of aquatic life. Most impacts are to early life stages of fish and shellfish. Aquatic organisms drawn into CWIS are either impinged (I) on components of the intake structure or entrained (E) in the cooling water system itself. In CWA section 316(b) and in this rulemaking, these impacts are referred to as *adverse environmental impact* (AEI). Rates of I&E depend on species characteristics, the facility's environmental setting, and the location, design, construction and capacity of the facility's CWIS. In addition to direct losses of aquatic organisms from I&E, a number of indirect, ecosystem-level effects may also occur, including (1) disruption of aquatic food webs resulting from the loss of impinged and entrained organisms that provide food for other species, (2) disruption of nutrient cycling and other biochemical processes, (3) alteration of species composition and overall levels of biodiversity, and (4) degradation of the overall aquatic environment. In addition to the impacts of a single CWIS on currents and other local habitat features, environmental degradation can result from the cumulative impact of multiple intake structures operating in the same watershed or intakes located within an area where intake effects interact with other environmental stressors. Finally, although it is difficult to measure, the compensatory ability of an aquatic population, which is the capacity for a species to increase survival, growth, or reproduction rates in response to decreased population, is likely compromised by I&E and the cumulative impact of other stressors in the environment over extended periods of time.

The beneficiaries of fish protection at cooling water intakes include fisherman, both recreational and commercial, and people interested in well-functioning and healthy aquatic ecosystems. While most people consume electricity, they consume electricity in differing amounts, and may not be uniformly interested in, or willing to pay for, fish protection. Thus, there is imperfect overlap between those who could be required to pay for fish protection and those who would benefit from fish protection. Those who desire more fish protection have extremely limited opportunities in which they can express their willingness to pay for fish protection in market transactions that result in fish protection. In addition, deregulation in the electric industry has made it more difficult for merchant power producers to both remain competitive and pass along to consumers costs associated with fish protection, relative to rate-regulated electric utilities that are vertically integrated.

Fish protection at cooling water intakes is also variable, based on species and their migrations, waterbody, size of a cooling water intake, presence of multiple facilities on a waterbody, and many more variables that are highly site specific. In addition, given the history of litigation around this section of the Clean Water Act, states have, in some instances, administratively continued permits while awaiting final Federal action, and thus fish protection has been delayed, in some instances for decades.

Promulgation of today's final rule will complete EPA's regulations under section 316(b) of the Clean Water Act. This rule includes a national performance standard as the BTA to address impingement mortality (IM) at existing CWIS. This national standard for impingement reflects EPA's assessment that impingement reduction technology is available, feasible and demonstrated, and thus BTA for existing facilities. The impingement mortality standard is based on modified traveling screens with fish returns and includes a performance standard as one compliance alternative, but also offers six other compliance alternatives that are equivalent or better in performance. With regard to entrainment, this rule contains a national BTA standard that is a process for a site-specific determination of entrainment mitigation requirements at existing CWIS. The entrainment provision reflects EPA's assessment that there is no single technology basis that is BTA for entrainment at existing facilities, but instead a number of factors that are best accounted for on a site-specific basis. Site-specific decision making may lead to a determination by the NPDES permitting authority that entrainment requirements should be based on variable speed pumps, water reuse, fine mesh screens, a closed-cycle recirculating system, or some combination of technologies that constitutes BTA for the individual site. The site-specific decision-making may also lead to no additional technologies being required.

In addition to the above provisions, which apply to existing units at existing facilities, the rule establishes a BTA standard, for both impingement mortality and entrainment, for new units at existing facilities. Under this standard, new units at existing facilities will be subject to requirements similar to the section 316(b) requirements for new facilities subject to the previously promulgated Phase I rule.

In addition, there is a need to regulate even those facilities that adopt the most effective technology. Closed-cycle cooling is a technology that recirculates cooling water, reducing withdrawals from surface waters. Closed-cycle cooling can reduce water withdrawals by at least 95 percent, compared to once-through cooling, but is itself capital intensive. Facilities that retrofit to closed-cycle cooling without also modifying their condenser may not be able to operate at full capacity during summer peak periods of electricity demand (replacing the condenser would require longer outages). Operators who retrofit closed-cycle cooling systems have a financial incentive not to run their system in closed-cycle mode during summer months. Thus, decision making at facilities that use cooling water may not take society's preferences for fish protection into account in their actions.

EPA notes that some facilities have installed, and some NPDES permits require, controls that protect aquatic organisms from impingement and entrainment. Facilities may have adopted controls as good stewards. Directors may have required controls to meet state water quality standards, particularly with regard to temperature. Based on our evaluation of available evidence, these actions have not been widespread enough to discourage cooling water withdrawals from waters where they have the greatest impact on aquatic organisms.

3. Costs and Benefits

As presented in Exhibit I–1, EPA assessed the expected costs to society for complying with the final rule, accounting for both the existing CWIS unit provision and the new unit provision, as $275 million and $297 million per year at the 3 percent and 7 percent discount rates, respectively. These costs reflect permit applications, studies, recordkeeping, monitoring, and reporting required by the rule. The costs also include costs of technologies for

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complying with the BTA for IM. The cost of additional technologies that may be required to meet the site-specific BTA for entrainment are not included in this analysis because, as explained in Section VII, EPA cannot estimate, with any level of certainty, what site-specific determinations will be made based on the analyses that will be generated as a result of the national BTA standard for entrainment decision-making established by today's rule.

EPA estimates that today's final rule—including standards for both existing units and new units at existing facilities—will achieve monetized benefits to society of $33 million and $29 million annually, again depending on the discount rate. This estimate of benefits omits important categories of benefits that EPA expects the rule will achieve, such as most of the benefits associated with fish other than commercially and recreationally harvested fish. As a result, these estimates are likely to understate substantially the rule's expected benefits to society. In estimating the benefits of today's rule, EPA did not rely on the results of the stated preference survey conducted by the Agency and described in the June 12, 2012 Notice of Data Availability (77 FR 34927 (June 12, 2012)). Included in the monetized benefits is EPA's estimate that the final rule will reduce greenhouse gas (GHG) emissions by 9.3 million tons of CO_2-equivalent emissions over the 40-year compliance period for this analysis. Based on this reduction in GHG emissions, EPA estimates benefits to society (based on social cost of carbon (DCN [2] 12–4853)) ranging from $12 million to $13 million annually (see Section 9 of the BA), depending on the discount rate and other assumptions in the social cost of carbon analysis.

EXHIBIT I–1—TOTAL ANNUALIZED SOCIAL COSTS AND BENEFITS FOR THE FINAL RULE

[in millions, 2011 dollars]

	Existing units	New units	Total
Using 3 percent discount rate:			
Social Costs	$272.4	$2.5	$274.9
Social Benefits	33.0	−0.2	32.8
Using 7 percent discount rate:			
Social Costs	295.3	2.0	297.3
Social Benefits	28.7	−0.1	28.6

EPA expects that the final rule will have relatively minor economic impacts on the regulated facilities, the entities that own them, and the overall electric power sector, which is the industry most affected by today's rule. Under the rule's existing unit provisions, EPA estimates that a substantial majority (86 percent) of electric generators will incur compliance costs of less than 1 percent of revenue, indicating the minor impact of the rule on these facilities.

EPA also expects very small impacts on the non-power sector component of regulated facilities. EPA estimates that 504 out of 509 facilities will incur costs less than one percent of revenue, five will incur costs between one and three percent, and none will incur costs greater than 3 percent. In addition, EPA estimates that no manufacturing facilities will close as a result of today's rule, and that only 12 facilities in the non-power sector component will experience moderate financial stress short of closure. These 12 facilities represent approximately 3 percent of the estimated total regulated facilities in the non-power sector component.

At the level of the entities that own regulated facilities, EPA estimates that 91 to 94 percent of entities owning regulated facilities in the electric power sector will incur compliance costs of less than 1 percent of revenue under the rule's existing unit provisions. Likewise, for the non-power sector component of regulated facilities, EPA estimates that 90 to 95 percent of entities owning regulated facilities will incur compliance costs of less than 1 percent of revenue under the rule's existing unit provisions.

Finally, EPA estimates that today's rule will have a minor impact on the overall electric power sector and electricity consumers. EPA estimates that the rule will not affect national or regional electricity markets on a long-term basis. In addition, EPA expects there to be no effects of the final rule on the reliability of electricity generation, transmission and distribution. In terms of consumer impacts, EPA estimates, on average, across the United States, that the final rule will increase electricity production costs by 0.009 cents per kWh, causing an estimated 0.1 percent increase in average electricity prices. The corresponding annual increase in electricity costs is approximately $1.03 per household.

B. Scope of Today's Rulemaking

Today's final rule represents the last stage in EPA's efforts to implement section 316(b) of the CWA. In the course of their operations, electric power facilities and certain manufacturing facilities use large amounts of water either for cooling purposes or in their manufacturing processes. Such facilities typically remove water from nearby sources using ''cooling water intake structures.'' The structures associated with water removal pose a number of threats to the environment. Principally, aquatic organisms are squashed against intake screens—impingement—or drawn into the cooling system—entrainment. Section 316(b) requires EPA to develop standards for cooling water intakes structures.

Today's final rule establishes national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at existing facilities that reflect the BTA for minimizing the adverse environmental impacts– impingement and entrainment—associated with the use of these structures. It represents the culmination of EPA's efforts to implement section 316(b) and, as such, fulfills EPA's obligation under a settlement agreement entered in the United States District Court for the Southern District of New York in *Riverkeeper Inc., et al.* v. *Jackson,* No. 93 Civ. 0314 (AGS). (For a more detailed discussion of the settlement agreement, see Section II.C.)

This final rule establishes requirements for all existing facilities with a DIF (design intake flow) of more

[2] DCN refers to a document control number. An index of DCNs can be found in the docket for this action.

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than 2 mgd. EPA estimates that a total of 1,065 facilities will be subject to the final rule, including 544 Electric Generators, 509 Manufacturers in six Primary Manufacturing Industries, and 12 Manufacturers in Other Industries. The rule also clarifies the definition and requirements for new units at existing facilities. The applicable requirements are summarized in Exhibits I–2 and I–3.

EXHIBIT I–2—APPLICABILITY BY PHASE OF THE 316(B) RULES

Facility characteristic	Applicable rule
New power-generating or manufacturing facility	Phase I rule.
New offshore oil and gas facility	Phase III rule.
New unit at an existing power-generating or manufacturing facility	This rule.
Existing power-generating or manufacturing facility	This rule.
Existing offshore oil and gas facility and offshore seafood processing facilities	This rule (site-specific, BPJ).

EXHIBIT I–3—APPLICABLE REQUIREMENTS OF TODAY'S RULE FOR EXISTING FACILITIES

Facility characteristic	Applicable requirements
Existing facility with a DIF greater than 2 mgd and an AIF (actual intake flow) greater than 125 mgd.	Impingement mortality standards at § 125.94(c) and site-specific entrainment requirements under the entrainment standards at § 125.94(d) (Additional study requirements at § 122.21(r)(1)(ii)(B)).
Existing facility with a DIF greater than 2 mgd but AIF not greater than 125 mgd.	Impingement mortality standards at § 125.94(c) and site-specific entrainment requirements under the entrainment standards at § 125.94(d).
New unit at an existing facility where the facility has a DIF greater than 2 mgd.	Impingement mortality and entrainment standards for new units at § 125.94(e).
Other existing facility with a DIF of 2 mgd or smaller or that has an intake structure that withdraws less than 25 percent of the water for cooling purposes on an actual intake flow basis.	Case-by-case BPJ permitting per § 125.90(b).

At an early stage in the development of section 316(b) requirements, EPA divided its rulemaking effort into three phases. The first addressed new facilities, the second, large existing electricity utility facilities and the third, the remaining electric generating facilities not addressed in the earlier phases as well as existing manufacturing operations. As EPA's analysis progressed, however, it became clear that it could address in one rulemaking cooling water intake structures at both existing steam electric generating and manufacturing facilities. From a biological perspective, the effect of intake structures on impingement and entrainment [3] does not differ depending on whether an intake structure is associated with a power plant or a manufacturer. In 2009, following judicial challenge of the Phase II rule, EPA asked the U.S. Court of Appeals for the Second Circuit to remand the rule to the Agency for further action consistent with a decision by the U.S. Supreme Court in *Entergy Corp.* v. *Riverkeeper, Inc.* and the Second Circuit's decision on the Phase II rule in *Riverkeeper, Inc.* v. *EPA,* 475 F.3d 83 (2d cir. 2007). In 2009, EPA also asked the U.S. Court of Appeals for the Fifth Circuit to remand certain aspects of EPA's Phase III rule that were before it in a petition for review. Today's rule responds to these remands as well to the Second Circuit's remand of limited aspects of the Phase I section 316(b) rule in *Riverkeeper Inc.* v. *Johnson,* 358 F.3d 174 (2nd Cir. 2004). EPA has here consolidated the universe of potentially regulated facilities from the remanded 2004 Phase II rule with the existing facilities in the remanded 2006 Phase III rule for establishing requirements in a single proceeding.

C. General Applicability

This rule applies to owners and operators of existing facilities [4] that meet all following criteria:

- The facility is a point source that uses or, in the case of new units at an existing facility, proposes to use cooling water from one or more cooling water intake structures, including a cooling water intake structure operated by an independent supplier not otherwise subject to 316(b) requirements that withdraws water from waters of the United States and provides cooling water to the facility by any sort of contract or other arrangement;
- The facility-wide DIF for all cooling water intake structures at the facility is greater than 2 mgd;
- The cooling water intake structure withdraws cooling water from waters of the United States; and
- At least 25 percent of the water actually withdrawn—actual intake flow (AIF)—is used exclusively for cooling purposes.

A facility may choose to demonstrate compliance with the final rule for the entire facility, or for each individual cooling water intake structure.

EPA is adopting provisions that promote the reuse of water from certain sources for cooling and that ensure that the rule does not discourage the reuse of cooling water for other uses such as process water. For example, the final rule at § 125.91(c) specifies that obtaining cooling water from a public water system, using reclaimed water from wastewater treatment facilities or desalination plants, or recycling treated process wastewater effluent (such as wastewater treatment plant ''gray'' water) does not constitute use of a cooling water intake structure for purposes of this rule. In addition, the definition of cooling water at § 125.92 provides that cooling water obtained from a public water system, reclaimed water from wastewater treatment facilities or desalination plants, treated effluent from a manufacturing facility, or cooling water that is used in a manufacturing process either before or

[3] Throughout the preamble and support documents, the terms ''entrainment'' and ''entrainment mortality'' may be used interchangeably. As described below, EPA continues to assume that, in most instances, entrainment mortality is 100 percent, leaving little distinction between the two terms.

[4] Throughout the preamble, the terms ''owner or operator of a facility'' and ''facility'' may be used interchangeably. In cases where the preamble may state that a facility is required to do a given activity, it should be interpreted as the owner or operator of the facility is required to do the activity.

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after it is used for cooling as process water is not considered cooling water for the purposes of calculating the percentage of a facility's intake flow that is used for cooling purposes. Therefore, water used for both cooling and non-cooling purposes does not count toward the 25 percent threshold. Examples of water withdrawn for non-cooling purposes includes water withdrawn for warming by LNG (liquefied natural gas) facilities and water withdrawn for public water systems by desalinization facilities.

Today's rule focuses on those facilities that are significant users of cooling water. The rule provides that only those facilities that use 25 percent or more of the water withdrawn exclusively for cooling purposes (on an actual intake flow basis) are subject to the rule. EPA previously considered a number of cut-points or approaches for focusing the applicability of the rule (66 FR 28854, May 25, 2001 and 66 FR 65288, December 18, 2001). EPA used the 25 percent threshold in each of the Phase I, II, and III rules. For this rule, EPA did not receive any new data supporting a different threshold or identify new approaches to the applicability of the rule. Consequently, EPA is adopting 25 percent as the threshold for the percent of flow used for cooling purposes to ensure that a large majority of cooling water withdrawn from waters of the United States are subject to the rule's requirements for minimizing adverse environmental impact. Because power-generating facilities typically use far more than 25 percent of the water they withdraw exclusively for cooling purposes, the 25 percent threshold will ensure that intake structures accounting for nearly all cooling water used by the power sector are addressed by today's rule requirements. While manufacturing facilities often withdraw water for more purposes than cooling, the majority of the water is withdrawn from a single intake structure. Once water passes through the intake, water can be apportioned to any desired use, including uses that are not related to cooling. However, as long as at least 25 percent of the water is used exclusively for cooling purposes, the intake is subject to the requirements of today's rule. EPA estimates that approximately 70 percent of manufacturers and 87 percent of power-generating facilities that meet the first three criteria for applicability outlined above also use 25 percent or more of intake water for cooling and thus are subject to today's rule. (See 66 FR 65288, December 18, 2001.)

For facilities that are below any of the applicability thresholds in today's rule—for example, a facility that withdraws less than 25 percent of the intake flow for cooling purposes—the Director must set appropriate requirements on a case-by-case basis, using BPJ, based on § 125.90(b). Today's rule is not intended to constrain permit writers at the Federal, State, or Tribal level, from addressing such cooling water intake structures. Also, EPA decided to adopt for the final rule the proposed provision that requires the owners and operators for certain categories of facilities (existing offshore oil and gas facilities, existing offshore seafood processing facilities and offshore LNG terminals) to meet case-by-case BTA impingement and entrainment requirements, established by the Director. Such facilities are subject to permit conditions implementing CWA section 316(b) if the facility is a point source that uses a cooling water intake structure and has, or is required to have, an NPDES permit.

D. What is an ''existing facility'' for purposes of the final rule?

In today's rule, EPA is defining the term ''existing facility'' to include any facility subject to section 316(b) that is not a ''new facility'' as defined in 40 CFR 125.83 (the Phase I rule).

A point source discharger would be subject to Phase I or today's rule even if the cooling water intake structure it uses is not located at the facility.[5] In addition, modifications or additions to the cooling water intake structure (or even the total replacement of an existing cooling water intake structure with a new one) does not convert an otherwise unchanged existing facility into a new facility, regardless of the purpose of such changes (e.g., to comply with today's rule or to increase capacity). Rather, the determination as to whether a facility is new (Phase I) or existing (today's rule) focuses on whether or not it is a greenfield or stand-alone facility whose processes are substantially independent of an existing facility, and whether or not there are changes to the cooling water intake. New facility does not include new units that are added to a facility for purposes of the same general industrial operation. For example, a new peaking unit at an existing electrical generating station is not a new facility (40 CFR 125.83). The distinction between an existing facility and a new facility is separate from the distinction between an existing unit at an existing facility and a new unit at an existing facility, which is discussed at greater length in Section J below.

E. What is ''cooling water'' and what is a ''cooling water intake structure?''

EPA has slightly revised the definition of *cooling water intake structure* from proposal for today's rule. In today's final rule, a cooling water intake structure is defined as the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the United States. Under the definition in today's rule, the cooling water intake structure extends from the point at which water is first withdrawn from Waters of the United States up to, and including, the intake pumps. The final rule at § 125.91(c) also specifies that obtaining cooling water from a public water system, using reclaimed water from wastewater treatment facilities (such as wastewater treatment plant ''gray'' water) or desalination plants, or recycling treated process wastewater effluent does not constitute use of a cooling water intake structure for purposes of applicability of this rule. As a point of clarification, facilities subject to today's rule may choose to use another entity's treated wastewater as a source of cooling water, thereby reducing cooling water withdrawals and associated impingement and entrainment. EPA notes that because the entity providing the wastewater for cooling has already treated it to meet any applicable discharge requirements (e.g., otherwise applicable effluent limitations guidelines and standards, water quality standards, etc.), EPA is not concerned that this provision will lead to pollutant discharges that would not have occurred if the treated effluent had been discharged by the other entity.

Today's rule adopts the new facility rule's definition of *cooling water* as water used for contact or noncontact cooling, including water used for equipment cooling, evaporative cooling tower makeup, and dilution of effluent heat content. The definition specifies that the intended use of cooling water is to absorb waste heat [not being efficiently used or recaptured for production and thus] rejected from the process or processes used or from auxiliary operations on the facility's premises. The definition also indicates that cooling water obtained from a public water system, reclaimed water from wastewater treatment facilities or desalination plants, treated effluent from a manufacturing facility, or cooling water that is used in a manufacturing process either before or after it is used for cooling as process water would not

[5] For example, a facility might purchase its cooling water from a nearby facility that owns and operates a cooling water intake structure.

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be considered cooling water for the purposes of determining whether 25 percent or more of the actual intake flow is cooling water. This clarification is necessary because cooling water intake structures typically bring water into a facility for numerous purposes, including industrial processes; use as circulating water, service water, or evaporative cooling tower makeup water; dilution of effluent heat content; equipment cooling; and air conditioning. Note, however, that all intake water (including cooling and non-cooling process) is included in the determination as to whether the 2 mgd DIF threshold for covered intake structures is met.

F. Would my facility be covered only if it is a point source discharger?

Today's rule applies only to facilities that have an NPDES permit or are required to obtain one. This is the same requirement EPA included in the Phase I new facility rule at § 125.81(a)(1). Requirements for complying with CWA section 316(b) will continue to be applied through NPDES permits.

On the basis of the Agency's review of potential existing facilities that employ cooling water intake structures, the Agency anticipates that most facilities will control the intake structure that supplies them with cooling water, and discharge some combination of their cooling water, wastewater, or stormwater to a water of the United States through a point source regulated by an NPDES permit. In such cases, the facility's NPDES permit must include the requirements for the cooling water intake structure. If an existing facility's only NPDES permit is a general permit for stormwater discharges, the Agency anticipates that the Director will write an individual NPDES permit containing requirements for the facility's cooling water intake structure. Alternatively, requirements applicable to cooling water intake structures could be incorporated into general permits. If requirements are placed into a general permit, they must meet the requirements set out at 40 CFR 122.28.

As EPA stated in the preamble to the final Phase I rule (66 FR 65256, December 18, 2001), the Agency encourages the Director to closely examine scenarios in which a facility withdraws significant amounts of cooling water from waters of the United States but is not required to obtain an NPDES permit. As appropriate, the Director must apply other legal requirements, where applicable, such as CWA sections 401 or 404, the Coastal Zone Management Act, the National Environmental Policy Act, the Endangered Species Act, or similar State or Tribal authorities to address adverse environmental impact caused by cooling water intake structures at those facilities.

G. Would my facility be covered if it withdraws water from waters of the united states? what if my facility obtains cooling water from an independent supplier?

The requirements in today's rule apply to cooling water intake structures that have the design capacity to withdraw amounts of water greater than 2 mgd from waters of the United States. Waters of the United States include the broad range of surface waters that meet the regulatory definition at 40 CFR 122.2 and 40 CFR 230.3, which includes lakes, ponds, reservoirs, nontidal rivers or streams, tidal rivers, estuaries, fjords, oceans, bays, and coves. These potential sources of cooling water can be adversely affected by impingement and entrainment.

Some facilities use an impoundment such as a man-made pond or reservoir as part of a cooling system. Cooling water is withdrawn from the pond or reservoir at one point and heated water is discharged to a different point, using mixing and evaporative processes. As explained above, section 316(b) and today's final rule apply only to withdrawals of cooling water from waters of the United States; accordingly, to the extent a facility withdraws cooling water from a pond or reservoir that is not itself a water of the United States and does not withdraw any make-up water from waters of the U.S., the requirements of today's rule do not apply to such systems. Impoundments that are not constructed from a waters of the U.S. but do withdraw make-up water from waters of the U.S. can be closed-cycle recirculating systems subject to the requirements of today's rule, provided that withdrawal for make-up water is minimized.

Facilities that withdraw cooling water from impoundments that are in whole or in part waters of the United States and that meet the other criteria for coverage (including the requirement that the facility has or will be required to obtain an NPDES permit) are subject to today's rule. In today's rule, the agency is defining the term closed-cycle recirculating system to include, at § 125.92(c)(2), a system with impoundments of waters of the U.S. where the impoundment was lawfully created [6] for the purpose of serving as part of the cooling water system. In determining whether an impoundment qualifies as a closed-cycle recirculating system, the Director will determine whether the make-up water withdrawals for such a system have been minimized. In many cases, EPA expects that such make-up water withdrawals are commensurate with the flows of a closed-cycle cooling tower. Some of these impoundments may qualify for the waste treatment exclusion found in the definition of a waste treatment system at 40 CFR 122.2, and this rule does not affect the applicability of that exclusion.

EPA does not intend for this rule to change the regulatory status of impoundments. Impoundments are addressed in the definition of *waters of the United States* at 40 CFR 122.2 and 40 CFR 230.3. The determination whether an impoundment is a water of the United States is to be made by the Director on a site-specific basis. The EPA and the U.S. Army Corps of Engineers have jointly issued jurisdictional guidance concerning the term *waters of the United States* in light of the Supreme Court's decision in *Solid Waste Agency of Northern Cook County* v. *U.S. Army Corps of Engineers,* 531 U.S. 159 (2001) (SWANCC). A copy of that guidance was published as an Appendix to an Advanced Notice of Proposed Rulemaking on the definition of the phrase *waters of the United States,* see 68 FR 1991, January 15, 2003, which is at *http://www.epa.gov/owow/wetlands/pdf/ANPRM-FR.pdf*. The agencies additionally published guidance in 2008 regarding the term *waters of the United States* in light of both the *SWANCC* and subsequent *Rapanos* case (*Rapanos* v. *United States,* 547 U.S. 715 (2006)). The EPA published a proposed revision to the definition of ''Waters of the United States'' under the Clean Water Act on April 21, 2014 (see 79 FR 22188).

EPA recognizes that some impoundments may be man-made waterbodies that support artificially managed and stocked fish populations. As a result, EPA has included a provision in today's final rule to allow the Director to waive certain permit application requirements for such facilities. Note, however, that these facilities are still subject to the final rule.

EPA acknowledges that the point of compliance for facilities located on

[6] The owner or operator of the facility would provide documentation such as the project purpose statement for the Clean Water Act section 404 permit obtained to construct the impoundment. If the impoundment was created prior to the CWA requirement to obtain a section 404 permit, the owner or operator would provide any other license or permit obtained to lawfully construct the impoundment for the purposes of a cooling water system.

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impoundments may also vary depending on where the facility withdraws from a water of the United States. Again, only cooling water systems with withdrawals of cooling water from waters of the United States are covered by section 316(b) and today's rule. Because a facility may withdraw cooling water from a water of the United States either directly or as makeup water for a closed-cycle cooling system, the Director may determine where within a facility's cooling water intake structure is or are the facility's point or points of compliance.

The Agency recognizes that some facilities that have or are required to have an NPDES permit might not own and operate the intake structure that supplies their facility with cooling water. In addressing facilities that have or are required to have an NPDES permit that do not directly control the intake structure that supplies their facility with cooling water, § 125.91 provides (similar to the new facility rule) that facilities that obtain cooling water from a public water system, use reclaimed water from a wastewater treatment facility or desalinization plant, or use treated effluent are not deemed to be using a cooling water intake structure for purposes of this rule. However, obtaining water from another entity that is withdrawing water from a water of the United States will be counted as using a cooling water intake structure for purposes of determining whether an entity meets the threshold requirements of the rule. For example, facilities operated by separate entities might be located on the same, adjacent, or nearby property. One of these facilities might take in cooling water and then transfer it to other facilities that discharge to a water of the United States. Section 125.91(b) specifies that use of a cooling water intake structure includes obtaining cooling water by any sort of contract or arrangement with one or more independent suppliers of cooling water if the supplier or suppliers withdraw water from waters of the United States but that is not itself a new or existing facility subject to CWA section 316(b), except if it is a public water system, a wastewater treatment facility or desalination plant providing reclaimed water, or a facility providing treated effluent for reuse as cooling water pursuant to § 125.91(c).

As a practical matter, the existing facilities subject to this rule are the largest users of cooling water and therefore typically withdraw volumes of water for cooling that warrant owning the cooling water intake structures. In some cases, such as at nuclear power plants or critical baseload facilities, the need for cooling water includes safety and reliability reasons that would likely preclude any independent supplier arrangements. Therefore, EPA expects this provision will have only limited applicability. EPA is nevertheless retaining the provision to prevent facilities from circumventing the requirements of today's rule by creating arrangements to receive cooling water from an entity that is not itself subject to today's rule and that is not otherwise explicitly exempt from today's rule (such as drinking water or treatment plant discharges reused as cooling water).

H. What intake flow thresholds result in an existing facility being subject to the final rule?

EPA determines the cooling water flow at a facility in two ways. The first is based on the DIF, which reflects the maximum intake flow the facility is capable of withdrawing. While this normally is limited by the capacity of the cooling water intake pumps, other parts of the cooling water intake system could impose physical limitations on the maximum intake flow the facility is capable of withdrawing. The second method for determining cooling water flow is based on the AIF, which reflects the actual volume of water withdrawn by the facility. EPA has defined AIF to be the average water withdrawn each year over the preceding three years.[7] Both of these methods are used in today's rule.

Today's final rule applies to facilities that have a total DIF of greater than 2 mgd (see § 125.91).[8] At a threshold of 2 mgd, today's rule covers 99.8 percent of the total water withdrawals by utilities and other industrial sources (if the other criteria for coverage are met), which includes 70 percent of manufacturing facilities and 87 percent of electric generators. EPA also chose the greater than 2 mgd threshold because it was consistent with the applicability criteria in the Phase I rule.[9]

There are substantial environmental benefits that will accrue with a threshold of 2 mgd. For example, EPA's analysis indicates that greater than 82 percent of impinged fish mortality across all facilities would be prevented by this rule at this threshold. EPA also considered a threshold of 50 mgd. The record includes 38 studies documenting IM at more than 40 facilities with flows lower than 50 mgd. Further, the industry questionnaire demonstrates that such facilities are twice as likely to have no controls in place for impingement or entrainment than are facilities with intake flows greater than 50 mgd. In addition, lower intake flow facilities can have similar impacts to those of larger flow facilities as sizable numbers of fish are impinged by lower flow facilities. Moreover, site-specific impacts of lower flow facilities may be significant, particularly where threatened or endangered species are present.

Although smaller flow facilities (those less than 50 mgd) constitute a large proportion of the total number of the facilities regulated (476 of 1,065), the total compliance cost for these smaller facilities are only a small portion of the total compliance cost of the rule ($23 million of $275 million). Thus any perceived aggregate cost savings from setting the threshold higher than 2 mgd would be minimal.

There is no appreciable difference in the cost effectiveness of the rule with a higher applicability threshold. For example, the cost effectiveness of the rule with a threshold of 2 mgd is $0.42 per age-one equivalent losses (A1E). At a threshold of 50 mgd the cost effectiveness would be $0.41 per A1E. In addition, the incremental cost of the 2 mgd threshold relative to a 50 mgd threshold is negligible for the electric power industry at less than 0.1 percent of annual electricity sector revenue, which exceeds $126 billion. The facility-level impacts are negligible to zero at either 2 or 50 mgd threshold. At the 2 mgd threshold, only 5 (1 percent) of the manufacturing facilities have a cost-to revenue ratio exceeding 1 percent (but less than 3 percent). While this drops to zero facilities at the 50 mgd threshold, the difference of 5 facilities out of 509 facilities is not significant. Costs for lower flow facilities are so small that the average annual household utility bill would not measurably decrease by changing the threshold from 2 to 50 mgd. While 58 percent of the small facilities affected by the final rule are below 50 mgd, 40 percent of them already meet one of the compliance alternatives for impingement mortality of the rule and likely would not need to install any additional compliance technologies. And small businesses account for only 17 percent of facilities at or below 50 mgd, demonstrating that there would

[7] For permit terms subsequent to the first permit issued under today's rule, the rule defines AIF as the average flows over the previous 5 years.

[8] The 2004 Phase II rule would have applied to existing power-generating facilities with a design intake flow of 50 mgd or greater. Facilities potentially regulated by the Phase III rule had a DIF of greater than 2 mgd.

[9] For more information, see 65 FR 49067, August 10, 2000.

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not be a disproportionate impact on small businesses at a 2 mgd threshold.

Thus, EPA concluded that the threshold of 2 mgd ensures that the users of cooling water causing the most adverse environmental impact are subject to the rule. Raising the threshold for applicability of the rule's impingement and entrainment requirements to 50 mgd as some commenters suggested was not supportable given the statistics and information described above.

Raising the applicability threshold to 50 mgd would have meant that 476 facilities, almost half of the 1,065 facilities subject to the national standards set by today's rule, would not be subject to the rule. Ignoring so many facilities when setting national standards fails to apply the common sense approaches set forth in this rule for minimizing adverse environmental impacts from cooling water intake structures.

Excluding such a large number of facilities from this rule would create regulatory uncertainty for those facilities since they would remain subject to CWA permitting requirements, but without the benefits of the structure of this rule. Directors would have an obligation to establish controls on a case-by-case basis for these lower flow facilities using a BPJ analysis instead of using the more straightforward and transparent provisions of setting controls based on national standards contained in this rule. Such BPJ analyses can be uncertain, and can be time consuming and complex to develop for both Directors and owners and operators of facilities. Case-by-case BPJ permits (instead of permits based on the national standards in today's rule) would likely increase the time and costs to states for such permits to be developed, further delaying the minimization of adverse environmental impacts called for by CWA section 316(b). Maintaining an applicability threshold of 2 mgd DIF best combines the shared goals of minimizing adverse environmental impacts as required by the CWA, and the predictability and flexibility contained in the rule.

EPA acknowledges that there may be circumstances where flexibility in the application of the rule may be called for and the rule so provides. For example, some low flow facilities that withdraw a small proportion of the mean annual flow of a river may warrant special consideration by the Director. As an illustration, if a facility withdraws less than 50 mgd AIF, withdraws less than 5 percent of mean annual flow of the river on which it is located (if on a river or stream), and is not co-located with other facilities with CWISs such that it contributes to a larger share of mean annual flow, the Director may determine that the facility is a candidate for consideration under the de minimis provisions contained at § 125.94(c)(11). In the case of facilities on lakes and reservoirs, co-location would be better determined by multiple CWIS facilities on the same waterbody, rather than distance.

In either case, the flexibilities contained in the rule for the Director to consider the site-specific characteristics of each intake structure within the national standard provide a useful mechanism for facilities with lower intake flows and low impacts to be considered.

EPA is continuing to base applicability on DIF as opposed to AIF for several reasons. In contrast to AIF, DIF is a fixed value based on the design of the facility's operating system and the capacity of the circulating and other water intake pumps. This provides clarity because the DIF does not vary with facility operations, except in limited circumstances, such as when a facility undergoes major modifications. On the other hand, actual flows can vary significantly over sometimes short periods. For example, a peaking power plant might have an AIF close to the DIF during times of full energy production, but an AIF of zero during lengthy periods of standby. Use of DIF provides clarity as to regulatory status, is indicative of the potential magnitude of environmental impact, and avoids the need for monitoring to confirm a facility's status. For more information about these thresholds, see 69 FR 41611, July 9, 2004.

Under this rule, all facilities with a DIF of greater than 2 mgd, that meet the other three criteria for applicability of today's rule, must submit basic information describing the facility, Source Water Physical Data, Source Water Biological Characterization Data, and Cooling Water Intake System Data. In addition, these facilities must submit additional facility-specific information including the selected impingement compliance option, and operational status of each of the facility's units.[10] Certain facilities withdrawing the largest volumes of water for cooling purposes have additional information and study requirements such as relevant biological survival studies and the entrainment study as described below.

The final rule uses AIF rather than DIF for purposes of determining which facilities must provide the information required in § 122.21(r)(9) through (13), referred to as the entrainment study. Thus, the rule provides that any facility subject to the rule with actual flows in excess of 125 mgd must provide an entrainment study with its permit application (which includes the Entrainment Characterization Study at § 122.21(r)(9)).[11] Adverse environmental impacts from entrainment result from actual water withdrawals, and not the maximum designed level of withdrawal. Further, using actual flow might encourage some facilities to adopt operational practices to reduce their flows below 125 mgd AIF to avoid collecting supplemental data and submitting the additional entrainment study. Furthermore, any facility that has DIF greater than 2 mgd, that meets the other three criteria for applicability of today's rule, is required to submit basic information that will allow the Director to verify its determination of whether it meets the 125 mgd AIF threshold.

EPA has selected an administrative threshold of 125 mgd AIF for submission of the entrainment study because this threshold will capture 90 percent of the actual flows but will apply to only 30 percent of existing facilities. Further, based on EPA's data there are no closed-cycle recirculating systems in use above this threshold. The 125 mgd AIF threshold will significantly limit facility burden at more than two-thirds of the potentially affected facilities while focusing the Director on major cooling water withdrawals. Contrary to a number of public comments, however, EPA is not implying or concluding that the 125 mgd threshold is an indicator that facilities withdrawing less than 125 mgd are (1) not causing any adverse impacts or (2) automatically qualify as meeting BTA. In other words, the threshold, while justified on a technical basis, does not result in exemptions from the rule. Instead, EPA is making a policy decision as to which facilities must provide a certain level and type of information. The Director, of course, will retain the discretion to require reasonable information to make informed decisions at the smaller facilities. The 125 mgd threshold focuses on the facilities with the highest intake flows and the highest likelihood of causing adverse impacts; it is not an

[10] The final rule allows the Director to waive certain information submission requirements for facilities that already employ closed-cycle cooling.

[11] For impoundments constructed in uplands or not in waters of the United States, the point of compliance for measuring AIF to determine if it is greater than 125 mgd is the intake into the impoundment from the waters of the United States.

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indicator that facilities under that threshold are no longer of concern in the final rule.

In today's rule, EPA seeks to clarify that for some facilities, the DIF is not necessarily the maximum flow associated with the intake pumps. For example, a power plant might have redundant circulating pumps, or might have pumps with a name plate rating that exceeds the maximum water throughput of the associated piping. EPA intends for the DIF to reflect the maximum rate at which a facility can physically withdraw water from a source waterbody (usually normalized to a daily rate in mgd). This also means that a facility that has permanently taken a pump out of service should be able to consider such constraints when reporting its DIF, as the facility's capacity to withdraw water may have fundamentally changed. Additionally, if a facility's flow is limited by constrictions in the piping or other physical limitations (e.g., a given portion of its cooling system that can only safely handle a given amount of flow) and that flow is lower than the DIF for the pumps, the facility should be able to consider such constraints when reporting its DIF, because it is not capable of withdrawing its full pumping DIF without compromising the cooling system.

I. What are the requirements for existing offshore oil and gas facilities, offshore seafood processing facilities or LNG terminals BTA requirements under the final rule?

Under today's rule, existing offshore oil and gas facilities, existing offshore seafood processing facilities and existing LNG terminals will be subject to section 316(b) requirements on a BPJ basis. In the Phase III rule, EPA studied offshore oil and gas facilities and offshore seafood processing facilities [12] and could not identify any technologies (beyond the protective screens already in use) that are technically feasible for reducing impingement or entrainment in such existing facilities.[13] As discussed in the Phase III rule, known technologies that could further reduce impingement or entrainment would result in unacceptable changes in the envelope of existing platforms, drilling rigs, mobile offshore drilling units, offshore seafood processing facilities, and similar facilities as the technologies would project out from the hull, potentially decrease the seaworthiness, and potentially interfere with structural components of the hull. It is also EPA's view that for many of these facilities, the cooling water withdrawals are most substantial when the facilities are operating far out at sea and, therefore, not withdrawing from a water of the United States. EPA is aware that LNG facilities may withdraw hundreds of million gallons per day of seawater for warming (re-gasification). However, some existing LNG facilities might still withdraw water where 25 percent or more of the water is used for cooling purposes on an actual intake flow basis. EPA has not identified a uniformly applicable and available technology for minimizing impingement mortality and entrainment at these facilities. However, technologies might be available for some existing LNG facilities. LNG facilities that withdraw any volume of water for cooling purposes will be subject to site-specific, BPJ determinations of BTA.

EPA has not identified any new data or approaches that would result in a different determination. Therefore, EPA has adopted the approach of the proposed rule and is requiring that NPDES Permit Directors, on a case-by-case basis using BPJ, determine BTA for existing offshore oil and gas extraction facilities, existing offshore seafood processing facilities, and existing LNG terminals.

J. What is a ''new unit'' and how are new units addressed under the final rule?

Today's rule establishes requirements for new units at an existing facility that are different than those applicable to existing units at an existing facility. The requirements for new units at existing facilities are modeled after the requirements for a new facility in the Phase I rule. Under today's rule, a new unit means a newly built, stand-alone unit, whose construction begins after the effective date of the rule. EPA is also clarifying that while Phase I does not include units newly constructed at an existing facility for the same general industrial operation, such units do constitute a new unit at existing facilities and, as such, are subject to today's final rule.

On the basis of the public comments received on how to define ''new unit,'' EPA provides a clear definition for this term in the final rule. The definition for a new unit at an existing facility establishes a clear regulatory framework for both affected facilities and Directors. This definition captures facilities that are undergoing major construction projects involving the construction of a new stand-alone unit, while not discouraging upgrades. For example, a nuclear facility conducting a measurement uncertainty capture or a stretch power uprate, or a fossil-fuel facility repowering an existing generating unit, would not be considered to result in the relevant unit becoming a new unit. As another example, under this definition placing an offshore facility or vessel into a dry dock for maintenance or repair does not result in either the offshore facility, vessel, or the dry dock as being defined as a new unit.

Section VI discusses EPA's rationale for establishing the definitions for new units at existing facilities described below.

1. Electric Generators

The final rule defines a new unit at an existing facility as a newly built, stand-alone unit that is constructed at an existing facility and that does not meet the definition of a new facility. An existing unit that is repowered or undergoes significant modifications (such as where the turbine and condenser are replaced) is not considered a new unit. Exhibit I–4 below provides several examples and whether these hypothetical units will be defined as new or existing units.

EXHIBIT I–4—EXAMPLES OF NEW AND EXISTING UNITS AT EXISTING ELECTRIC GENERATION FACILITIES

Examples of new units at an existing facility	Examples of existing units
A unit that is constructed at a stand-alone location at an existing facility regardless of any plans to retire any other unit at the facility in the future.	A unit that is repowered or undergoes significant modifications. A retrofitted with a new boiler or fuel type.

[12] EPA studied naval vessels and cruise ships as part of its developing a general NPDES permit for discharges from oceangoing vessels. (For more information, see *http://cfpub.epa.gov/npdes/home.cfm?program_id=350*.) EPA studied offshore seafood processing facilities and oil and gas exploration facilities in the 316(b) Phase III rule.

[13] As discussed in today's preamble, requirements for new offshore facilities that were set forth in the Phase III rule remain in effect.

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2. Manufacturers

At manufacturing facilities that generate electricity onsite, the previous discussion of how to define new units at existing electric generating facilities generally applies. Some manufacturers employ different industrial processes than an electric generator and therefore have different industrial equipment (including cooling systems). In particular, manufacturers may not use a steam condenser or steam turbine for their industrial processes, making the definition for ''repowering'' above inappropriate for manufacturing facilities. However, manufacturers may have opportunities to reuse cooling water that power plants do not, and in site visits, EPA found many manufacturers have conducted energy and water audits resulting in significant reductions in water withdrawals. The final rule provides for manufacturers to receive credit for such reductions in fresh water withdrawals.

It is not as easy to identify a similar conceptual approach for defining new manufacturing units at existing manufacturing facilities because waste heat can be generated from a variety of sources including exothermic processes, product heating and cooling, and the processing, handling, treating, or disposal of feed streams, waste streams, by-products, and recycled components. Sources may include direct cooling transferred across an inert material (e.g., heat exchanger, steam condenser), indirect cooling using a working fluid (e.g., chillers, refrigeration), or contact cooling where cooling water comes into direct contact with a product or process stream.[14] Unlike electric generating units where the majority of cooling water comes from a single process source (the steam condenser), manufacturing units may include many separate non-contact or contact cooling water sources dispersed throughout the production processes and the facility. Thus, a definition for manufacturing units must take into consideration a broader category of cooling water sources.

For power generators, the term ''generating unit'' is quite clear since there is only one product (electricity), the non-contact cooling water predominantly comes from one source, and the application of the term is well understood in the industry. But for some manufacturing facilities, it may be unclear what constitutes a ''unit'' since manufacturing processes can involve numerous vertically integrated processes or production steps that may involve intermediate products. For example, a unit could encompass an entire series of production steps (start to finish) or simply the individual steps. Also, there may be ancillary support equipment that serves various functions and it is not clear whether this will be considered a unit or part of a unit. For example, a petroleum refiner will typically include various processes such as distillation, cracking, hydrotreating, coking, reforming, and different types of various products. Various intermediate products from these processes may be directly transported (piped) from one process to another or stored and some may be sold. And because various intermediate and final process products may be blended into different products, differentiating units on a product or intermediate product basis may not provide clear distinctions.

For these reasons EPA has defined new unit to simply mean a new stand-alone unit. A new unit may include one or more distinct production lines that are added to increase product output and operate parallel to and independently of existing production equipment. A new unit does not include the replacement or rebuilding of one or more distinct production lines or distinct processes involving the replacement of the majority of the waste heat producing equipment that serves as sources of non-contact cooling water and the majority of the heat exchanging equipment that contributes heat to the non-contact cooling water. Such modifications alone do not render the unit a new unit. A unit undergoing such modifications would continue to be considered an existing unit and would be regulated under the existing unit provisions of this rule. This definition therefore does not impose any disincentives for the replacement/upgrade of individual components or ancillary equipment alone.

Exhibit I–5 below provides several examples of whether these hypothetical units are defined as new or existing units. As noted above, the Director has broad discretion to assess the scope of any modifications at the manufacturing facility and to determine whether the new construction comprises a stand-alone unit. For the purposes of today's final rule, the Director does not need to address whether the stand-alone unit is for the same general industrial purposes, or whether the new unit is a replacement unit. The key factors in assessing whether a unit will be defined as new lies with whether the construction results in a stand-alone unit.

EXHIBIT I–5—EXAMPLES OF NEW AND EXISTING UNITS AT MANUFACTURERS

Examples of new units at an existing facility	Examples of existing units at an existing facility
A unit that is constructed at a stand-alone location at an existing facility (either adjacent to existing units or on newly acquired or developed property) regardless of any plans to retire any other unit at the facility in the future.	A unit where only the waste heat generating process equipment or the cooling system equipment is replaced.
A unit that is constructed adjacent to an existing unit for the same industrial activity (such as expanding the production output by building a second unit as a stand-alone unit next to the existing unit).	A unit where modifications are made to the waste heat generating process equipment or the cooling system (e.g., optimization, repairs, upgrades to operational elements).
	Replacement or upgrade of ancillary equipment (e.g., pumps, motors, HVAC, etc.).

K. Amendments Related to the Phase I Rule

EPA is making limited changes to the Phase I rule at 40 CFR Part 125 Subpart I. The changes fall into two categories. The first is deleting the provision in the Phase I rule that would allow a facility to demonstrate compliance with the Phase I BTA requirements in whole or in part through restoration measures. This change responds to the decision of the U.S. Court of Appeals for the Second Circuit, which remanded these provisions to EPA because it concluded that the statute did not authorize

[14] Note that EPA did not include the contact cooling category as part of its analysis of possible closed-cycle recirculating system requirements but contact cooling water does nonetheless fall within the definition of cooling water at § 125.92.

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restoration measures to comply with CWA section 316(b) requirements. The second category of changes reflects technical corrections or errors that do not change the substance of the Phase I rule. EPA has not reopened any other aspects of the Phase I rule other than the provisions specifically noted here.

1. Restoration Provisions Not Authorized

The Phase I final rule established two compliance tracks. Track I requires facilities to restrict intake flow and velocity. Track II gives a facility the option of demonstrating to the Director that the control measures it employs will reduce the level of adverse environmental impact to a comparable level to what would be achieved by meeting the Track I requirements. As part of this demonstration, Track II originally allowed a facility to make use of restoration measures. The Comprehensive Demonstration Study allowed a quantitative or qualitative demonstration that restoration measures would meet, in whole or in part, the performance levels of Track I. Similarly, the Verification Monitoring Plan could be tailored to verify that the restoration measures would maintain the fish and shellfish in the waterbody at a substantially similar level to that which would be achieved under Track I. See 66 FR 65280–65281, December 18, 2001.

Upon legal challenge, the Second Circuit Court concluded that EPA exceeded its authority by allowing new facilities to comply with CWA section 316(b) through restoration measures, and remanded that aspect of the rule to EPA. The Supreme Court did not grant the petitions for writs of certiorari concerning restoration provisions. Today's final rule amends Phase I to remove those provisions in §§ 125.84(d) and 125.89(b)(1)(ii) authorizing restoration measures in conformance with the Second's Circuit's decision. Today's rule also specifically deletes permit application requirements contained in the Comprehensive Demonstration Study at § 125.86(c)(2)(ii); evaluation of proposed restoration measures at § 125.86(c)(2)(iv)(C); and verification monitoring requirements at § 125.86(c)(2)(iv)(D)(2) that are specific to restoration. EPA acknowledges these changes might reduce the alternatives available to some Phase I facilities. EPA notes, however, that the deletion of restoration measures does not otherwise alter the availability of Track II. In any event, EPA's determination of BTA for Phase I did not presume reliance on the restoration provisions, and the deletion of restoration measures in no way alters the Agency's BTA determination for Phase I facilities.

2. Corrections to Subpart I

Today's final rule changes the applicability of the technical requirements at § 125.84 and permit application requirements at § 125.86 statement to match the applicability statement at § 125.81(a)(3). The applicability in all three instances should specify DIF or withdrawals ''greater'' than the specified value of 2 mgd. See Basis for the Final Regulation at 66 FR 65270, December 18, 2001.

Today's rule also corrects the source waterbody flow information submission requirements. Track I requirements at § 125.84(b)(3) apply to new facilities that withdraw equal to or greater than 10 mgd. Track I requirements at § 125.84(c)(2) apply to facilities that withdraw less than 10 mgd. The source waterbody flow information under § 125.86(b)(3) requires a facility to demonstrate it has met the flow requirements of both §§ 125.84(b)(3) ''and'' 125.84(c)(2). However, a facility cannot be subject to both §§ 125.84(b)(3) and 125.84(c)(2) at the same time. Accordingly, the word ''and'' should read as ''or'' in § 125.86(b)(3).

In addition, today's final rule corrects the permit application requirement for the Source Water Biological Characterization at § 122.21(r)(4). Accordingly, references to the Source Water Biological Characterization should read as (r)(4). However, the references to the Source Water Biological Characterization at § 125.86(b)(4)(iii), at § 125.87(a), and at § 125.87(a)(2) incorrectly refer to § 122.21(r)(3) and are thus being corrected.

II. Legal Authority for and Background of the Final Regulation

A. Legal Authority

Today's final rule is issued under the authority of Clean Water Act sections 101, 301, 304, 308, 316, 401, 402, 501, and 510, 33 U.S.C. 1251, 1311, 1314, 1318, 1326, 1341, 1342, 1361, and 1370.

B. Purpose of the Regulation

The purpose of today's rule is to reduce impingement and entrainment of fish, shellfish and other aquatic organisms at cooling water intake structures. Today's rule establishes national requirements for cooling water intake structures at existing facilities under section 316(b) of the CWA. That section provides that any standard established pursuant to CWA sections 301 or 306 and applicable to a point source must require that the location, design, construction, and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact. Today's rule establishes requirements applicable to all existing power-generating facilities and existing manufacturing and industrial facilities that are point sources, that have a DIF of greater than 2 mgd from waters of the United States, and use at least 25 percent of the water they withdraw exclusively for cooling purposes on an actual intake flow basis. In addition, EPA is today also making minor changes to its earlier rule establishing section 316(b) requirements for new facilities. Specifically, EPA is removing a provision that would have allowed a restoration-based alternative for complying with performance standards as well as the associated monitoring and other requirements for demonstrating compliance.

C. Background

1. The Clean Water Act

a. General

The Federal Water Pollution Control Act, also known as the CWA, 33 U.S.C. 1251 et seq., seeks to ''restore and maintain the chemical, physical, and biological integrity of the nation's waters.'' 33 U.S.C. 1251(a). Among the goals of the Act is, wherever attainable, an interim goal of water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for recreation in and on the water. 33 U.S.C. 1251(a)(2).

In furtherance of these objectives, the CWA establishes a comprehensive regulatory program, key elements of which are (1) a prohibition on the discharge of pollutants from point sources to waters of the United States, except in compliance with the statute and (2) authority for EPA or authorized States or Tribes to issue NPDES permits that authorize and regulate the discharge of pollutants.

CWA section 402 authorizes EPA (or an authorized State or Tribe) to issue an NPDES permit to any person discharging any pollutant or combination of pollutants from a point source into waters of the United States. Forty-six States and one U.S. territory are authorized under section 402(b) to administer the NPDES permitting program. NPDES permits restrict the types and amounts of pollutants, including heat, that may be discharged from various industrial, commercial, and other sources of wastewater. These permits control the discharge of pollutants by requiring dischargers to meet technology-based and possibly water-quality-based effluent limitations.

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Under section 316(b), NPDES permits are required to contain conditions to implement the requirements of section 316(b).

CWA section 510 provides that, except as provided in the CWA, nothing will preclude or deny the right of any State (or political subdivision thereof) to adopt or enforce any requirement respecting control or abatement of pollution; except that if a limitation, prohibition or standard of performance is in effect under the CWA, such State may not adopt any other limitation, prohibition, or standard of performance which is less stringent than the limitation, prohibition, or standard of performance under the Act. EPA interprets this to reserve for the States authority to implement requirements that are more stringent than the Federal requirements under state law. *PUD No. 1 of Jefferson County* v. *Washington Dep't of Ecology,* 511 U.S. 700, 705 (1994). New York and California have enacted State requirements that are at least as stringent as those of the final rule, and therefore, EPA has analyzed facilities in those States that are subject to those State requirements as already complying with the final rule.[15] Those facilities still must comply with the administrative requirements of the final rule.

CWA sections 301, 304, and 306 require that EPA develop technology-based effluent limitations guidelines and new source performance standards that are used as the basis for discharge requirements in wastewater discharge permits. EPA develops these effluent limitations guidelines and standards for categories of industrial dischargers on the basis of the pollutants of concern discharged by the industry, the degree of control that can be attained using various levels of pollution control technology appropriate for each industrial process or subcategory, consideration of various economic tests implemented under the authority of the CWA for each level of control, and other factors identified in CWA sections 304 and 306 (such as non-water quality environmental impacts including energy impacts). EPA has promulgated regulations setting effluent limitations guidelines and standards under CWA sections 301, 304, and 306 for 57 industry categories. See 40 CFR parts 405 through 471. EPA has established effluent limitations guidelines and standards that apply to the industry categories that are the largest users of cooling water (e.g., steam electric power generation, paper and allied products, petroleum refining, iron and steel manufacturing, and chemicals and allied products), as well as many other industrial categories that may include facilities subject to this final rule.

b. Section 316(b)

Section 316(b) states, in full,

> Any standard established pursuant to section 301 or section 306 of [the Clean Water] Act and applicable to a point source shall require 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. 1326(b). This provision is unique among CWA provisions because it addresses the adverse environmental impact caused specifically by the intake of cooling water, in contrast to other provisions of the Act that regulate the discharge of pollutants into waters of the United States.

The CWA does not further define the substantive standard specified in section 316(b)—''best technology available for minimizing adverse environmental impact'' (BTA). 33 U.S.C. 1326(b). The standard that cooling water intake structures must achieve under section 316(b)—BTA—is a different standard from those prescribed under sections 301 and 306 of the Act. *Riverkeeper, Inc.* v. *EPA,* 358 F.3d 174 (2d Cir. 2004). Moreover, unlike sections 304 and 306, section 316(b) does not set forth the specific factors that the EPA must consider in determining BTA. BTA is ''the only substantive statutory requirement explicitly applicable to the intake structure regulations.'' *Id.* at 186. Unlike other provisions of the Act, section 316(b) standards are not subject to a ''host'' of other requirements or limitations. *Ibid.* There is no ''elucidating language applicable to the BTA test.'' *Entergy Corp.* v. *Riverkeeper, Inc.,* 556 U.S. 208, 221 (2009).[16]

Section 316(b) does, however, cross-reference sections 301 and 306 of the CWA by stating that any standards established pursuant to those sections also require that cooling water intake structures reflect BTA. *Ibid.* This cross reference, in the view of the Second Circuit, is an invitation, not a straitjacket. EPA ''may'' look to the referenced sections in discerning what factors Congress intended EPA to consider in determining BTA.

Because section 316(b) refers to sections 301 and 306 but provides a different standard (''best technology available for minimizing adverse environmental impact'' instead of, for example, ''best available demonstrated control technology'') and does not explicitly provide that regulations pursuant to section 316(b) are subject to the requirements of sections 301 and 306, we think it is permissible for the EPA to look to those sections for guidance but to decide that not every statutory directive contained therein is applicable to the Rule.

The terse statutory description of BTA and the absence of any prescribed statutory factors for consideration in determining BTA suggest that Congress delegated EPA significant rulemaking discretion in this area.[17]

As noted, in contrast to effluent limitations guidelines and standards, the CWA does not describe the factors to be considered in establishing section 316(b) substantive performance requirements that reflect the ''best technology available for minimizing adverse environmental impact'' nor does it require that EPA develop uniform nationally applicable performance requirements through rule making.

The U.S. Supreme Court has, however, recently provided guidance, in *Entergy Corp.* v. *Riverkeeper, Inc.,* in interpreting section 316(b) and what factors EPA may consider in its standard-setting. That decision addressed the question of whether CWA section 316(b) authorizes EPA to compare costs and benefits of various technologies when setting national performance standards for cooling water intake structures under CWA section 316(b). In overturning EPA's earlier rule to establish section 316(b) requirements for existing facilities, the Second Circuit held that balancing costs and benefits was an impermissible factor for standard setting under section 316(b). The Supreme Court reversed and remanded the Second Circuit ruling in a 6–3 opinion authored by Justice Scalia. The Court held that it is permissible for EPA to consider a cost-benefit analysis in setting national performance standards for cooling water intake structures under section 316(b).

[15] For example, California policy addressing 19 coastal power plants would not affect the compliance costs of inland facilities.

[16] Included in an appendix to the decision is a table comparing CWA statutory standards under 301, 306 and 316(b), the table. In the column headed ''Statutorily Mandated Factors,'' for section 316(b), the table states ''N/A.''

[17] The Second Circuit has noted the limited legislative history for section 316(b). ''This paucity of legislative history, when measured against the volumes of drafts and speeches devoted to other aspects of the 1972 amendments, and when combined with the brevity of the provision itself, counsels against imputing much specific intent to Congress beyond the section's words themselves. To the extent the provision is silent on issues to which other sections speak, we hesitate to draw the negative inference that the brevity of *section 316(b)* reflects an intention to limit the EPA's authority rather than a desire to delegate significant rulemaking authority to the Agency.'' *Id.* at 187.

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The Court held that EPA has the discretion to consider costs and benefits under section 316(b) but is not required to do so. 556 U.S. 208, 222–23.

The Court's discussion of the language of section 316(b)—section 316(b) is ''unencumbered by specified statutory factors''—and its critique of the Second Circuit's decision affirms EPA's broad discretion to consider a number of factors in standard setting under section 316(b). While the Supreme Court's decision is limited to whether or not EPA may properly consider one factor (cost/benefit analysis) under section 316(b), the language also indicates that EPA has wide discretion in considering other factors that it deems relevant to 316(b) standard setting. 556 U.S. 208, 222 (2009). (''It is eminently reasonable to conclude that § *1326b's* silence is meant to convey nothing more than a refusal to tie the agency's hands as to whether cost-benefit analysis should be used, and if so to what degree.'').

Regarding the other factors EPA may, but is not mandated to, consider, as noted above, section 316(b) cross references CWA sections 301 and 306 by requiring that any standards established pursuant to those sections also must require that the location, design, construction and capacity of intake structures reflect BTA. Following the decisions of the Second Circuit in reviewing both the Phase I and Phase II rules, EPA has interpreted the cross reference as authorizing consideration of the factors considered under those provisions to help guide section 316(b) rulemaking without determining that each of those factors is applicable to this rule. Thus, for example, section 306 directs EPA to establish performance standards for new sources based on the BADT (best available demonstrated control technology). 33 U.S.C. 1316(a)(1). In establishing BADT, EPA ''shall take into consideration the cost of achieving such effluent reduction, and any non-water quality environmental impact and energy requirements.'' 33 U.S.C. 1316(b)(2)(B).

Similarly, CWA section 301 requires EPA, in establishing standards known as *effluent limitations guidelines,* to consider specified factors. For a complete discussion of factors considered in establishing section 301 effluent limits, see 76 FR 22178–22179, April 20, 2011. But, EPA in establishing section 316(b) standards is not constrained in what factors it considers or bound by any statutorily prescribed tests as is the case with sections 301 and 306. Consequently, while section 316(b) expressly refers to section 301 and 306, and, while it shares some of the same words used in sections 301(b) and 306, its language is different.[18] These differences in the statutory descriptions, coupled with the brevity of section 316(b) itself, prompt EPA to examine the factors described in section 301, 306 and, ultimately, section 304 where relevant in EPA's determination of the ''best technology available to minimize adverse environmental impact'' of cooling water for intake structures for existing facilities.

As noted above, there are significant differences between section 316(b) and sections 301, 304 and 306. See *Riverkeeper, Inc.* v. *United States Environmental Protection Agency* (2nd Cir. Feb. 3, 2004) (''not every statutory directive contained [in sections 301 and 306] is applicable'' to a section 316(b) rulemaking). Moreover, as the Supreme Court recognized, while the provisions governing the discharge of toxic pollutants must require the elimination of discharges if technically and economically achievable, section 316(b) has the less ambitious goal of ''minimizing adverse environmental impact.'' 556 U.S. at 219. In contrast to the effluent limitations provisions, the object of the best technology available is explicitly articulated by reference to the receiving water: To minimize adverse environmental impact in the waters from which cooling water is withdrawn. This difference is reflected in EPA's past practices in implementing sections 301, 304, as contrasted with 316(b). For example, EPA has established BAT effluent limitations guidelines and new source performance standards on the basis of the efficacy of one or more technologies to reduce pollutants in wastewater in relation to their costs without necessarily considering the impact on the receiving waters. This contrasts to 316(b) requirements which historically have been developed on a site-specific basis, where EPA has considered the costs of technologies in relation to the benefits of minimizing adverse environmental impact in establishing 316(b) requirements. In *Re Public Service Co. of New Hampshire,* 10 ERC 1257 (June 17, 1977); *In Re Public Service Co. of New Hampshire,* 1 EBAD 455 (Aug. 4, 1978); *Seacoast Anti-Pollution League* v. *Costle,* 597 F. 2d 306 (1st Cir. 1979). EPA concluded that, because both section 301 and 306 are expressly cross-referenced in section 316(b), EPA could reasonably interpret section 316(b) as authorizing consideration, where appropriate, of the same factors, including costs. EPA stresses that it may therefore consider some of the same factors, even if it is not legally required to consider them in the same way.

2. Early Litigation History

On January 19, 1993, a group of individuals and environmental organizations[19] filed, under CWA section 505(a)(2), 33 U.S.C. 1365(a)(2), a complaint in *Cronin, et. al.* v. *Reilly,* 93 Civ. 314 (LTS) (S.D.N.Y.). The plaintiffs alleged that EPA had failed to perform a nondiscretionary duty to issue regulations implementing CWA section 316(b), 33 U.S.C. 1326(b). In 1995, EPA and the plaintiffs executed a consent decree in the case. As amended, it provided for EPA to implement CWA section 316(b) by prescribed dates in the three separate rule-making proceedings. Phase I concerned cooling water intake structures at new facilities, Phase II existing power plants using large volumes of cooling water and Phase III for existing smaller-flow power plants and factories in at least four industrial sectors (pulp and paper making, petroleum and coal products manufacturing, chemical and allied manufacturing, and primary metal manufacturing). EPA promulgated the Phase I rule in December, 2001, the Phase II rule in July, 2004 and the Phase III rule in June, 2006.

On November 17, 2006, some of the same environmental organizations in the *Cronin* case filed a second complaint, amended on January 19, 2007, in *Riverkeeper, et al.* v. *EPA,* 06 Civ. 12987 (S.D.N.Y.) asserting that EPA's Phase III rule failed to discharge EPA's duty under CWA section 316(b).

On August 14, 2008, EPA filed a motion to terminate the *Cronin* proceeding because it had discharged its

[18] Compare ''best technology available for minimizing adverse environmental impacts'' with ''*best practicable control technology currently available'' (301(b)(1)A)), ''best conventional pollutant control technology (301(b)(2)(E)), ''best available technology economically achievable'' (301(b)(2)(A)), and best available demonstrated control technology, (306(b)(1)(B)).* Section 316(b), section 301(b)(1)(A)—the BPT provision—section *301(b)(2)(E)—the BCT provision*—section 301(b)(1)(B)—the BAT provision—and section 306(b)(2)(E). All include the terms ''*best,*'' ''*technology*,'' and ''*available*,'' but none also include the modifying phrase ''for minimizing adverse environmental impacts,'' found in section 316(b). See 33 U.S.C. 1311(b)(1)(A) and (2)(A).

[19] The plaintiffs are the following: Riverkeeper, Inc.; Alex Matthiessen, a/k/a The Hudson Riverkeeper; Maya K. Van Rossum, a/k/a The Delaware Riverkeeper; Terrance E. Backer, a/k/a The Soundkeeper; John Torgan, a/k/a The Narragansett BayKeeper; Joseph E. Payne, a/k/a The Casco BayKeeper; Leo O'Brien, a/k/a the San Francisco BayKeeper; Sue Joerger, a/k/a The Puget Soundkeeper; Steven E. Fleischli, a/k/a The Santa Monica BayKeeper; Andrew Willner, a/k/a The New York/New Jersey Baykeeper; The Long Island Soundkeeper Fund, Inc.; The New York Coastal Fishermen's Association, Inc.; and The American Littoral Society, Inc.

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obligations (to take final action) under the decree with respect to the 2004 Phase II and 2006 Phase III rulemakings. Subsequently, EPA entered into a settlement with the plaintiffs in both lawsuits. Under the settlement agreement, EPA agreed to sign a notice of a proposed rulemaking implementing CWA section 316(b) at existing facilities no later than March 14, 2011, and to sign a notice taking final action on the proposed rule no later than July 27, 2012. Plaintiffs agreed to seek dismissal of both their suits, subject to a request to reopen the *Cronin* proceeding if EPA failed to meet the agreed deadlines. The district courts have now entered orders of dismissal. On March 11, 2011, the parties agreed to an amendment to the settlement agreement to extend the date for proposal to March 28, 2011. On July 17, 2012, the parties agreed to an amendment to the settlement agreement to extend the date for the final rule to June 27, 2013. On June 21, 2013, the parties agreed to extend the date to November 4, 2013, to accommodate completion of formal consultation under the Endangered Species Act. In part due to the government shutdown, on November 12, 2013, the parties agreed to extend the date to January 14, 2014. On February 10, 2014, to continue progress on the Endangered Species Act (ESA) consultation process, the parties agreed to extend the date to April 17, 2014. Finally, on April 23 2014, in a conference with the court EPA informed the judge that the EPA and the Services would complete the ESA consultation, so that the EPA would sign the rule by May 16, 2014. The court entered an order provisionally reinstating the case if EPA failed to inform the court by May 19, 2014 that it had taken the contemplated action. On May 19, 2014, the Administrator signed this notice for publication in the **Federal Register**.

3. Prior EPA Actions To Address Cooling Water Intake Structures

a. 1976 Rulemaking

In April 1976, EPA promulgated regulations under section 316(b) that addressed cooling water intake structures. 41 FR 17387, April 26, 1976. The rule added a new § 401.14 to 40 CFR Chapter I that reiterated the requirements of CWA section 316(b). It also added a new part 402, which included three sections: (1) § 402.10 (Applicability), (2) § 402.11 (Specialized definitions), and (3) § 402.12 (Best technology available for cooling water intake structures). Section 402.10 stated that the provisions of part 402 applied to ''cooling water intake structures for point sources for which effluent limitations are established pursuant to section 301 or standards of performance are established pursuant to section 306 of the Act.'' Section 402.11 defined the terms *cooling water intake structure, location, design, construction, capacity,* and *Development Document.* Section 402.12 included the following language:

> ''The information contained in the Development Document shall be considered in determining whether the location, design, construction, and capacity of a cooling water intake structure of a point source subject to standards established under section 301 or 306 reflect the best technology available for minimizing adverse environmental impact.''

In 1977, electric utility companies challenged those regulations, arguing that EPA had failed to comply with the requirements of the Administrative Procedure Act in promulgating the rule. Specifically, the utilities argued that EPA had violated the Administrative Procedure Act in promulgating regulations mandating consideration of the information in the Development Document in establishing 316(b) conditions in individual NPDES permits because EPA had neither published the Development Document in the **Federal Register** nor properly incorporated the document into the rule by reference. The U.S. Court of Appeals for the Fourth Circuit agreed. The court determined that the information in the Development Document was part of the substance of a regulation imposing specific obligations in mandatory terms. As such, the information must either be published in the **Federal Register** in its entirety or to be reasonably available and properly incorporated by reference under **Federal Register** requirements. The court explained it did not object to site-specific implementation of the section 316(b) requirements (''[w]hile we emphasize we do not fault EPA for its point source by point source application''), it did require EPA to ''devise a less uncertain method of advising those affected of the conditions by which they are to be bound.'' *Appalachian Power Co.* v. *Train,* 566 F.2d 451, 457 (4th Cir. 1977). Without reaching the merits of the regulations themselves, the court remanded the rule. EPA later withdrew part 402. (See 44 FR 32956, June 7, 1979.) Section 402.10, however, now codified at § 401.14, remains in effect.

Following the Fourth Circuit remand of EPA's section 316(b) regulations in 1977, NPDES permit authorities have made decisions implementing CWA section 316(b) and § 401.14 without the direction of a national rule. EPA published draft guidance addressing section 316(b) implementation in 1977. See *Draft Guidance for Evaluating the Adverse Impact of Cooling Water Intake Structures on the Aquatic Environment: Section 316(b) Public Law 92–500* (U.S. EPA 1977). That draft guidance describes the studies recommended for evaluating the impact of cooling water intake structures on the aquatic environment and recommends a basis for determining the BTA for minimizing adverse environmental impact. The 1977 section 316(b) draft guidance states, ''[t]he environmental-intake interactions in question are highly site-specific and the decision as to best technology available for intake design, location, construction, and capacity must be made on a case-by-case basis'' (Section 316(b) Draft Guidance, U.S. EPA 1977, p. 4). This site-specific approach was also consistent with the approach described in the 1976 Development Document referenced in the remanded regulation. (See DCN 1–1056–TC from the Phase I docket.) The 1977 section 316(b) draft guidance suggested a general process for developing information needed to support section 316(b) decisions and presenting that information to the Director. The process involved developing a site-specific study of the environmental effects associated with each facility that uses one or more cooling water intake structures, and consideration of that study by the Director in determining whether the facility must make any changes for minimizing adverse environmental impact. Under this framework, the Director determined whether appropriate studies have been performed, whether a given facility has minimized adverse environmental impact, and what, if any, technologies may be required.

b. Phase I—New Facility Rule

i. Rulemaking

On November 9, 2001, EPA took final action on regulations governing cooling water intake structures at new facilities. See 66 FR 65255, December 18, 2001. On December 26, 2002, EPA made minor changes to the Phase I regulations. 67 FR 78947. The final Phase I new facility rule (40 CFR part 125, Subpart I) establishes requirements applicable to the location, design, construction, and capacity of cooling water intake structures at new facilities that have a design capacity to withdraw greater than 2 mgd and use at least 25 percent of the water they withdraw solely for cooling purposes on an actual intake flow basis.

In the new facility rule, EPA adopted a two-track approach. Under Track I, facilities that withdraw equal to or

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greater than 10 mgd were required to meet three requirements. First, the intake flow of the cooling water intake structure is restricted, at a minimum, to a level commensurate with that which could be attained by use of a closed-cycle, recirculating cooling system. Second, the design through-screen intake velocity is restricted to 0.5 fps (foot per second). Third, the total quantity of intake is restricted to a proportion of the mean annual flow of a freshwater river or stream, or to a level necessary to maintain the natural thermal stratification or turnover patterns (where present) of a lake or reservoir except in cases where the disruption is beneficial, or to a percentage of the tidal excursions of a tidal river or estuary. Further, if there are, for example, endangered or threatened species stressed by a facility's intake structure, a facility that would otherwise meet the applicable performance requirements may have to select and implement additional design and construction or operational measures to address impingement mortality and entrainment if these measures are inadequate to protect the species. Facilities with greater than 2 mgd but less than 10 mgd flows are not required to reduce intake flow to a level commensurate with a closed-cycle, recirculating cooling system, but they must still meet specific operational criteria.

Under Track II, a facility had the opportunity to demonstrate to the NPDES permitting authority (Director) that the technologies it employs will reduce the level of adverse environmental impact to a comparable level to what would be achieved by meeting the Track I requirements for restricting intake flow and velocity. In making this demonstration, the regulations allow a facility to rely on a combination of measures in addition to technology controls for reducing impingement and entrainment to achieve results equivalent to the Track I intake flow and velocity requirements. Among these measures, the rule would have allowed restoration of the affected waterbody through efforts such as restocking fish and improving the surrounding habitat to offset the adverse effects that would otherwise be caused by operating the intake structures. The Second Circuit, in reviewing the new facility rule, determined that section 316(b) did not authorize the use of restoration measures in complying with the EPA performance standard. (Note that EPA is removing the provision related to restoration measures from the CFR in this rulemaking but has included the above description of the Phase I rule for completeness.) For more information, see Section I above.

In addition, under the Phase I rule, the Director may establish less stringent alternative requirements for a facility if compliance with the Phase I standards would result in compliance costs wholly out of proportion to those EPA considered in establishing the Phase I requirements or would result in significant adverse impacts on local air quality, water resources, or local energy markets.

EPA specifically excluded new offshore oil and gas extraction facilities from the Phase I new facility rule but committed to consider establishing requirements for such facilities in the Phase III rulemaking. 66 FR 65338, December 18, 2001.

ii. Subsequent Litigation

Various environmental and industry groups challenged the Phase I rule. In February 2004, the Second Circuit sustained the entire rule except for the restoration provision, ruling that restoration was not a technology as provided for in section 316(b). With respect to the other provisions of the rule, the court concluded the Phase I rule was based on a reasonable interpretation of the applicable statute and sufficiently supported by the record. Restoration provisions of the rule were remanded to EPA for further rulemaking consistent with the court's decision. *Riverkeeper, Inc.* v. *EPA,* 358 F.3d 174, 191 (2nd Cir., 2004). Today's rule removes the restoration provisions from the Phase I rule. For more details, see Chapter I of this preamble.

c. Phase II—Large Flow Existing Power Plants

i. Rulemaking

On February 16, 2004, EPA took final action on regulations governing cooling water intake structures at certain existing power-producing facilities. 69 FR 41576, July 9, 2004. The final 2004 Phase II rule applied to existing facilities that are point sources; that, as their primary activity, both generate and transmit electric power or generate electric power for sale or transmission; that use or propose to use a cooling water intake structure with a total DIF of 50 mgd or more to withdraw water from waters of the United States; and that use at least 25 percent of the withdrawn water exclusively for cooling purposes on an actual intake flow basis. In addition, power producers fitting the description above were also subject to the final 2004 Phase II rule even if they obtain their cooling water from one or more independent suppliers of cooling water. Such facilities were subject to the rule if their supplier withdraws water from waters of the United States even if the supplier was not itself a 2004 Phase II existing facility. EPA included this provision to prevent circumvention of the 2004 Phase II rule requirements by a facility purchasing cooling water from entities not otherwise subject to section 316(b).

The final 2004 Phase II rule and preamble also clarified the definition of an *existing* power-producing facility. The 2004 Phase II rule defined an *existing facility* as ''any facility that commenced construction as described in § 122.29(b)(4) on or before January 17, 2002; and any modification of, or addition of a unit at such a facility that does not meet the definition of a new facility at § 125.83.'' Because the definition of the term *existing facility* was based in part on the Phase I definition of the term *new facility,* the preamble to the final 2004 Phase II rule also clarified and provided some examples of how the definition of *existing facility* might apply to certain changes at power-producing facilities.

Under the 2004 Phase II rule, EPA established BTA performance standards for the reduction of impingement mortality and, under certain circumstances, entrainment (see 69 FR 41590–41593, July 9, 2004). The performance standards consisted of ranges of reductions in impingement mortality and, if applicable, entrainment (e.g., reduce impingement mortality by 80 to 95 percent and/or entrainment by 60 to 90 percent) relative to a *calculation baseline* that reflected the level of impingement mortality and entrainment that would occur absent specific controls. These performance standards were not based on a single technology but, rather, on consideration of a suite of technologies that EPA determined were commercially available and economically achievable for the industries affected as a whole (69 FR 41598–41610, July 9, 2004). EPA based the impingement mortality and entrainment performance standards on a suite of technologies because it found no single technology to be effective at all affected facilities. For impingement standards, these technologies included the following: (1) Fine- and wide-mesh wedgewire screens, (2) barrier nets, (3) modified screens and fish return systems, (4) fish diversion systems, and (5) fine-mesh traveling screens and fish return systems. With regard to entrainment reduction, these technologies include the following: (1) Aquatic filter barrier systems, (2) fine-mesh wedgewire screens, and (3) fine-

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mesh traveling screens with fish return systems. Because EPA based the performance standards on a combination of technologies and because of the uncertainty inherent in predicting the efficacy of one or more of these technologies as applied to different facilities, EPA promulgated these standards as ranges. Furthermore, because the site-specific performance was based on a comparison to a once-through system without any specific controls on the shoreline near the source waterbody (i.e., calculation baseline, for more details see Section III.B.1 of the preamble to the proposed rule, 76 FR 22185, April 20, 2011), the rule also allowed facilities to receive credit toward meeting the performance standards for impingement and entrainment reduction associated with alternative locations of their intakes (e.g., deep water where fish and shellfish were less abundant).

The types of performance standard applicable to a facility (i.e., reductions in impingement mortality only or both impingement mortality and entrainment) were based on several factors, including the facility's location (i.e., source waterbody), rate of use (capacity utilization rate), and the proportion of the waterbody withdrawn.

The 2004 Phase II rule identified five compliance alternatives to meet the performance standards. A facility could demonstrate to the Director one of the following: (1) That it has already reduced its flow commensurate with a closed-cycle recirculating system (to meet both impingement mortality and entrainment), or that it has already reduced its maximum through-screen velocity to 0.5 fps or less (to meet the impingement performance standard only); (2) that its cooling water intake structure configuration meets the applicable performance standards; (3) that it has selected design and construction technologies, operational measures, and/or restoration measures that, in combination with any existing design and construction technologies, operational measures, and/or restoration measures, meet the applicable performance standards; (4) that it meets the applicability criteria and has installed and is properly operating and maintaining a rule-specified and/or approved State-specified design and construction technology (i.e., submerged cylindrical wedgewire screens) in accordance with § 125.99(a) or an alternative technology that meets the appropriate performance standards and is approved by the Director in accordance with § 125.99(b); or (5) that its costs of compliance would be significantly greater than either the costs considered by the Administrator for a like facility to meet the applicable performance standards, or the benefits of meeting the applicable performance standards at the facility. Under the cost-cost comparison alternative, a Director could determine that the cost of compliance for a facility would be significantly greater than the costs considered by EPA in establishing the applicable impingement mortality and entrainment performance standards. Similarly, under the cost-benefit comparison alternative, a Director could determine that the cost of compliance for a facility would be significantly greater than the benefits of complying with the applicable performance standards. If either of these determinations were made, the Director would have to make a site-specific determination of BTA for minimizing adverse environmental impact that came as close as practicable to meeting the applicable performance standards at a cost that did not significantly exceed either the costs EPA considered in establishing these standards or the site-specific benefits of meeting these standards.

The final 2004 Phase II rule also provided that a facility that chooses specified compliance alternatives might request that compliance with the requirements of the rule be determined on the basis of implementing a Technology Installation and Operation Plan (TIOP) that would indicate how the facility would install and ensure the efficacy, to the extent practicable, of design and construction technologies, and/or operational measures, and/or a Restoration Plan. The rule also established requirements for developing and submitting a TIOP (§ 125.95(b)(4)(ii)) and provisions that specified how compliance could be determined on the basis of implementing a TIOP (§ 125.94(d)). Under these provisions, a TIOP could be requested in the first permit term, and continued use of a TIOP could be requested where a facility was in compliance with such plan and/or its Restoration Plan.

ii. Subsequent Litigation

Industry, environmental stakeholders, and some States [20] challenged many aspects of the 2004 Phase II regulations. On January 25, 2007, the Second Circuit (*Riverkeeper, Inc.* v. *EPA,* 475 F.3d 83, (2d Cir., 2007)) upheld several provisions of the 2004 Phase II rule and remanded others to EPA for further rulemaking.

As noted above, for the 2004 Phase II rule EPA did not select closed-cycle cooling as BTA. Instead, EPA selected a suite of technologies to reflect BTA, including, for example, screens, aquatic filter barriers, and barrier nets. According to the chosen technologies, EPA established national performance standards for reducing impingement mortality and entrainment of fish and fish organisms but did not require the use of any specific technology. Among the aspects of the rule the Second Circuit remanded for further clarification was EPA's decision to reject closed-cycle cooling as BTA and EPA's determination of performance ranges as BTA. In addition, the Second Circuit found that, consistent with its Phase I decision, restoration was not authorized under the CWA as a technology for BTA and that EPA's cost-benefit site-specific compliance alternative was not in accord with the CWA. There are also several issues for which the court requested additional clarification and some instances where the court determined that EPA had failed to provide adequate notice and opportunity to comment on certain provisions of the rule.

iii. Suspension

As a result of the decision in *Riverkeeper, Inc.* v. *EPA,* 475 F.3d 83, (2d Cir., 2007), EPA, on July 9, 2007 (72 FR 37107) suspended the requirements for cooling water intake structures at 2004 Phase II existing facilities, pending further rulemaking. Specifically, EPA suspended the provisions in § 122.21(r)(1)(ii) and (r)(5), and part 125 Subpart J, with the exception of § 125.90(b). EPA explained that suspending the 2004 Phase II requirements was an appropriate response to the Second Circuit's decision and that such action would allow it to consider how to respond to the remand. In addition, suspending the 2004 Phase II rule was responsive to the concerns of the regulated community and permitting agencies, both of whom sought guidance regarding how to proceed in light of the approaching deadline for compliance with the remanded rule. EPA's suspension clarified that pending further rulemaking, permit requirements for cooling water intake structures at 2004 Phase II facilities should be established on a case-by-case, BPJ basis (see § 125.90(b)).

iv. Supreme Court Decision

Following the decision in the Second Circuit, several industry group litigants

[20] Rhode Island, Connecticut, Delaware, Massachusetts, New Jersey, and New York.

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petitioned the U.S. Supreme Court to hear an appeal regarding several issues in the case. *Entergy Corp.* v. *Riverkeeper, Inc. et al., S. Ct. No. 07–588, et al.* On April 14, 2008, the Supreme Court granted the petitions for writs of certiorari submitted by these 2004 Phase II litigants, but it limited its review to the issue of whether section 316(b) authorizes EPA to compare costs with benefits in determining BTA for cooling water intake structures. The Supreme Court held oral arguments in this case on December 2, 2008, and issued a decision on April 1, 2009. As explained above, the Supreme Court held that it is permissible for EPA to rely on cost-benefit analysis in decision making. The court indicated that the phrase ''best technology available for minimizing adverse environmental impact'' does not unambiguously preclude use of cost-benefit analysis in decision making. 566 U.S. at 223(2009). The ruling supports EPA's discretion to consider costs and benefits, but it imposes no obligation on the Agency to do so.

d. Phase III—Existing Power Plants Below 50 mgd, Existing Manufacturing Facilities, and New Offshore Oil and Gas Facilities

i. Rulemaking

On June 16, 2006, EPA published a final Phase III rule that established categorical regulations for new offshore oil and gas extraction facilities that have a DIF threshold of greater than 2 mgd and that withdraw at least 25 percent of the water exclusively for cooling purposes on an actual intake flow basis. The rule establishes requirements that address intake velocity, proportionate flow for sensitive locations, design and construction technologies or operational measures, monitoring and recordkeeping, based on if a facility employs a sea chest or not, and is fixed or not. Like the Phase I rule, this rule includes a Track II. In the Phase III rule, EPA declined to establish national standards for Phase III existing facilities. Instead it concluded that CWA section 316(b) requirements for electric generators with a DIF of less than 50 mgd and all existing manufacturing facilities would continue to be established on a case-by-case basis under the NPDES permit program using BPJ. (71 FR 35006, June 16, 2006).

ii. Subsequent Litigation

Following promulgation of the rule, a number of parties filed petitions for review that were subsequently consolidated for hearing in the U.S. Court of Appeals for the Fifth Circuit. In 2009, EPA petitioned the Fifth Circuit to remand to the Agency those parts of the rule that applied to existing facilities. Specifically, EPA requested remand of those provisions in the Phase III rule that establish 316(b) requirements at electric generators with a DIF of less than 50 mgd, and the provision establishing requirements for existing manufacturing facilities on a case-by-case basis using BPJ. This request did not affect the Phase III rule requirements that establish categorical regulations for new offshore oil and gas extraction facilities that have a DIF threshold of greater than 2 mgd and that withdraw at least 25 percent of the water exclusively for cooling purposes on an actual intake flow basis.

On July 23, 2010, the U.S. Court of Appeals for the Fifth Circuit issued a decision affirming the parts of Phase III rule relating to new offshore oil and gas facilities. The court granted EPA's motion to remand the rule with respect to existing facilities. In sustaining the requirements for new offshore oil and gas facilities, the Fifth Circuit upheld EPA's decision not to use cost benefit balancing in determining the requirements for these new facilities.

III. Environmental Effects Associated With Cooling Water Intake Structures

A. Introduction

Multiple types of adverse environmental effects may be associated with CWIS operations at regulated facilities. Many facilities employ once-through cooling water systems that impinge fishes and other aquatic organisms on intake screens. Impinged organisms may be killed, injured, or weakened. In addition, early life stage fish or planktonic organisms can be entrained by the CWIS and subjected to high velocity and pressure, increased temperature, and chemical anti-biofouling agents in the system. These factors are highly lethal in most cases, as early life stages of larvae are highly sensitive and very unlikely to survive entrainment. Even if an organism is entrained as an egg and survives, its chances of surviving beyond the larvae stage are dramatically lower than eggs that were never entrained. Thus, unless measures to protect larvae are in place, egg survival does not indicate that adverse environmental impacts have been avoided. Consistent with its treatment of entrainment in past 316(b) rules, EPA assumes for the purposes of a national rule that 100 percent of entrained organisms suffer mortality.

The effects of CWIS on aquatic habitats and biota in the waterbody do not occur in isolation from other ongoing physical, chemical, and biological stressors. Anthropogenic stressors may include: Degraded water and sediment quality, low dissolved oxygen (DO) levels, eutrophication, fishing, channel or shoreline (habitat) modification (intake structure and other flood or storm controls), hydrologic regime changes and invasive species. For example, many aquatic organisms subject to IM&E (impingement mortality and entrainment) reside in impaired (i.e., CWA 303(d) listed) waterbodies. The effects of anthropogenic stressors on biota may contribute to or compound the impact of IM&E, depending on the influence of location-specific factors. In addition to stressors acting on biota near a single CWIS, multiple CWISs and facilities located in close proximity on the same waterbody may have additive or cumulative effects on aquatic communities. And, although it is difficult to measure, the compensatory ability of an aquatic population, which is the capacity for a species to increase survival, growth, or reproduction rates in response to decreased population, is likely compromised by IM&E and the cumulative impact of other stressors in the environment over extended periods of time.

B. Major Anthropogenic Stressors in Aquatic Ecosystems

All ecosystems and their biota are subject to natural variability in environmental conditions (e.g., seasonal cycles, foliage presence) as well as periodic large-scale disturbances (e.g., drought, flood, fire). In contrast, anthropogenic stressors tend to be more chronic in nature and can often lead to long-term environmental degradation associated with decreased biodiversity, reduced primary and secondary production, and a lowered ecosystem resiliency (i.e., ability of the ecosystem to recover to its original state from perturbations).[21] Several of the more important anthropogenic stressors are discussed below, with CWIS-related impacts considered as a separate category of stress.

1. Habitat Loss

Structural aquatic habitat is generally recognized as the most significant determinant of the nature and composition of aquatic communities. Most 316(b) facilities have been built on shoreline locations where industrial buildings, roadways, canals, impoundments, and other water storage or conveyance structures have been

[21] Rapport, D. J., & Whitford, W. G. (1999). How Ecosystems Respond to Stress. BioScience, 49(3), 193–203. See DCN 10–4871.

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constructed at the cost of terrestrial, aquatic, and wetland habitats. The main impacts of aquatic habitat loss are a reduction in the number of fish in the environment, a concentration of fishery spawning and nursery areas in fewer locations, shifts in species dominance based on available habitat and local extirpation of historical fish species. Habitat loss in shoreline areas exacerbates the effect of CWIS losses because many fish species affected by IM&E rely heavily on coastal wetlands as nursery areas.

2. Water Quality and Impaired Waters

Poor water quality is a major stressor of aquatic biota and habitats. Degraded surface water and sediment contaminants reflect both current and past industrial, agricultural and urban land use and disposal practices. Poor water quality can limit the numbers, composition, and distribution of fish and invertebrates; reduce spawning effort and growth rates; select for pollution-tolerant species; cause periodic fishkills; or result in adverse bioaccumulative effects to piscivorous wildlife.

EPA has determined that the majority of surveyed facilities, including 71 percent of electric generators and 79 percent of sampled manufacturing facilities, are within two miles of an impaired (i.e., CWA section 303(d)-listed) waterbody.[22] These impairments are caused by a variety of chemical, physical, and biological factors. These factors include biological stressors, nutrients, organic enrichment/loading, bioaccumulation, toxics, unknown causes, and other forms of anthropogenic sources of pollution (e.g., atmospheric deposition of mercury leading to fish advisories). The combined impacts of impaired water quality may result in highly degraded or altered aquatic communities that are further impaired by IM&E associated with the operation of regulated facilities.

3. Overharvesting

Overharvesting is a general term describing the exploitation of an aquatic population beyond a level that is sustainable, sometimes to the point of significantly reducing the population relative to historic levels. Given that many fisheries regulated by the National Marine Fisheries Service (NMFS) are overfished on a continual basis, overharvesting is a particular problem for stocks also subject to IM&E.

4. Invasive Species

Non-indigenous invasive species (NIS) are a significant and increasingly prevalent stressor in both freshwater and marine environments. Approximately 300 NIS have become established in marine and estuarine habitats of the continental U.S., and the number of NIS continues to increase. Many NIS are nuisance species with undesirable effects on local communities.[23] For example, interactions between NIS and other anthropogenic stressors can affect the colonization and distribution of native species subject to CWIS impacts.

C. Effects of CWIS on Aquatic Ecosystems

The magnitude and regional importance of IM&E is a function of operational CWIS intake volumes and characteristics of the aquatic community in the region. Thus, for example, IM&E can contribute to impacts on threatened and endangered (T&E) species and reduce populations of ecologically critical aquatic organisms, including important organisms in an ecosystem's food web. In addition, IM&E may diminish the compensatory reserves of populations and reduce indigenous species populations, commercial fisheries, and recreational fisheries. Further, IM&E may stress overall communities and ecosystems, as evidenced by reductions in diversity or other changes in ecosystem structure or function. The direct and indirect impacts of CWIS may reduce other valuable ecosystem goods and services, including nutrient cycling and ecosystem stability.

1. Losses of Fish From Impingement Mortality and Entrainment

The most visible direct impacts of IM&E are the losses of large numbers of aquatic organisms, distributed non-uniformly among fish, benthic invertebrates, phytoplankton, zooplankton, and other susceptible aquatic taxa (e.g., sea turtles). These losses have immediate and direct effects on the population size and age distribution of affected species, and may cascade through food webs.

In some cases, IM&E has been shown to be a significant source of anthropogenic mortality of depleted stocks of commercially targeted species. For example, approximately 5.4 percent of the estimated A1E population of the Southern New England/Massachusetts stock of winter flounder (*Pseudopleuronectes americanus*) is lost to IM&E.[24] In addition to its effect on stocks of marine commercial fish species, IM&E increases the pressure on native freshwater species, such as lake whitefish (*Coregonus clupeaformi*) and yellow perch (*Perca flavescens*), whose populations have seen dramatic declines in recent years.[25]

IM&E is also likely to contribute to reduced population sizes of species targeted by commercial and recreational fishers, particularly for stocks that are being harvested at unsustainable levels and/or undergoing rebuilding. Thus, reducing IM&E may lead to more rapid stock recovery, a long-term increase in commercial fish catches, increased population stability following periods of poor recruitment and, as a consequence of increased resource utilization, an increased ability to minimize the invasion of exotic species.[26]

2. IM&E Effects on Threatened and Endangered Species

Populations of T&E (threatened and endangered) species may suffer increased mortality as direct or indirect consequences of IM&E. T&E species are vulnerable to future extinction or at risk of extinction in the near future and IM&E losses could either lengthen population recovery time, hasten the demise of these species, or counteract the effects of other conservation efforts. For this reason, the population-level and societal values of T&E losses are likely to be considered more important than the absolute number of losses that occur. Due to low population sizes, I&E mortality from CWISs may represent a substantial portion of the annual reproduction of T&E species.

3. Thermal Effects

One byproduct of once-through cooling water systems is a discharge of a heated effluent. Concerns about the impacts of heated effluents are

[22] Abt Associates, Inc. (2010). Source Water Body Comparisons (Under Work Assignment 2–09, Task 4) (pp. 13). Cambridge, MA. See DCN 10–4504.

[23] Ruiz, G. M., Fofonoff, P. W., Carlton, J. T., Wonham, M. J., & Hines, A. H. (2000). Invasion of Coastal Marine Communities in North America: Apparent Patterns, Processes, and Biases. Annual Review of Ecology & Systematics, 31, 481–531. See DCN 10–4880.

[24] Northeast Fisheries Science Center (NEFSC) of the NOAA National Marine Fisheries Service. (2011). 52nd Northeast Regional Stock Assessment Workshop (52nd SAW): Assessment Summary Report. DCN 12–4940.

[25] U.S. Department of the Interior (USDOI). (2004). Fisheries: Aquatic and Endangered Resources from *http://www.glsc.usgs.gov/main.php?content=research_risk&title=Species%20at%20Risk0&menu=research* [Retrieved June 23, 2004]; Wisconsin Department of Natural Resources (Wisconsin DNR). (2003). Adrift on the sea of life. Wisconsin Natural Resources, June, 17–21. See DCN 10–4914.

[26] Stachowicz, J. J., & Byrnes, J. E. (2006). Species Diversity, invasion success, and ecosystem functioning: disentangling the influence of resource competition, facilitation, and extrinsic factors. Marine Ecology—Progress Series, 311, 251–262. See DCN 10–4892.

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addressed by state water quality standards addressing temperature, rather than a national rule. Section 316(a) of the Clean Water Act provides a mechanism for variances from controls that could be imposed due to thermal effects. Based on a limited review of NPDES permits, to the extent that facilities have controls on cooling water intake structures, these controls have been required to meet water quality standards related to temperature.[27]

Thermal pollution has long been recognized as having multiple effects upon the structure and function of ecosystems.[28] Numerous studies have shown that thermal discharges may substantially alter the structure of the aquatic community by modifying photosynthetic, metabolic, and growth rates [29] and reducing levels of DO. Thermal pollution may also alter the location and timing of fish behaviors including spawning, aggregation, and migration, and may result in thermal shock-induced mortality for some species.[30] Adverse temperature effects are likely to be more pronounced in aquatic ecosystems that are already subject to other environmental stressors such as high biochemical oxygen demand (BOD) levels, sediment contamination, and pathogens. Reduced waterbody volume due to the effects of climate change and/or lengthy droughts could exacerbate these effects.

4. Chemical Effects

The release of chemicals in the discharge of once-through cooling waters is another environmental effect associated with industrial facility operations. These chemicals include metals from internal corrosion of pipes, valves and pumps (e.g., chromium, copper, iron, nickel, and zinc), additives (anti-corrosion and anti-scaling agents) and their byproducts, and materials from boiler blowdown and cleaning cycles. In addition to these pollutants, facilities also discharge anti-fouling biocide agents.

A review of the effects of chemical treatment and discharge into the environment suggests that direct ecotoxicity in discharge plumes is rarely observed beyond the point of discharge or in a mixing zone near the pipe outlet.[31] However, the presence of these chemicals in the receiving water may be additive to low-level chronic adverse effects from other anthropogenic stressors identified above.

5. Effects of Flow Alteration

The operation of CWISs and discharge returns significantly alter patterns of flow within receiving waters both in the immediate area of the CWIS intake and discharge pipe, and in mainstream waterbodies, particularly in inland riverine settings. In ecosystems with strongly delineated boundaries (i.e., rivers, lakes, enclosed bays, etc.), CWISs may withdraw and subsequently return a substantial proportion of water available to the ecosystem. Even in situations when the volume of water downstream of regulated facilities changes relatively little, the flow characteristics of the waterbody, including turbulence and water velocity, may be significantly altered.

Altered flow velocities and turbulence may lead to several changes in the physical environment. These changes can include sediment deposition, sediment transport, and turbidity, each of which plays a role in the physical structuring of ecosystems.[32] Flow velocity and turbulence are controlling biological factors in aquatic ecosystem health, and have been shown to alter feeding rates, settlement and recruitment, bioturbation, growth and population dynamics.[33]

Climate change is predicted to have variable effects on future river flow in different regions of the United States. Some rivers are expected to have large increases in flood flows while other basins will experience stress from low water levels. Thus, the adverse effects of flow alteration may increase or decrease over longer periods for larger rivers, depending on their location.

D. Community-Level or Indirect Effects of CWIS

In addition to the direct effects of CWISs, IM&E may alter a wide range of aquatic ecosystem functions and services at the community level. Many of these effects on aquatic community function and service are poorly characterized, given the limited scope of IM&E studies and an incomplete knowledge of baseline or pre-operational conditions within affected waters.

The operation of CWISs by facilities can lead to localized areas of depressed fish and shellfish abundance. Industrial facilities (and the intake volume they represent) are located in a non-uniform manner along coastlines and rivers. They may be clustered, such that the populations affected by IM&E are geographically heterogeneous. This can result in a highly localized and patchy distribution of aquatic organisms in regional areas.

IM&E may directly reduce species populations through the death of individual organisms, or may indirectly affect species populations by altering established predator-prey relationships and thereby disrupting ecological niches and food webs. For example, the loss of young-of-year predators, such as striped bass, or loss of important forage fish, such as menhaden and bay anchovy, may affect trophic relationships and alter food webs. IM&E may lead to reductions in local community biodiversity or in a loss of genetic diversity in individual fish populations. Because IM&E represents a selective pressure on early life stages, it may reduce the genetic diversity of resident fish and prevent the recovery of depleted stocks.[34] Also, because many stocks are differentiated by oceanic region and/or timing of migratory movements, IM&E could alter the seasonal migration and life cycle events of fish populations, which could have ramifications for predator species.

IM&E may also alter the pace of nutrient cycling and energy transfer through food webs. Fish species have been shown to have substantial effects on nitrogen, phosphorous, and carbon cycling due to storage and translocation effects.[35] These alterations in nutrient cycling could lead to redirection of nutrient flows to other components of the ecosystem including water column phytoplankton, benthic macroalgae and attached epiphytes, with subsequent changes to the condition of critical

[27] Abt Associates, Inc. (2010). Source Water Body Comparisons (Under Work Assignment 2–09, Task 4) (pp. 13). Cambridge, MA. See DCN 10–4504.

[28] Abt Associates, Inc. (2009). Summary of Ecological Effects of Thermal Discharge (pp. 28). Cambridge, MA. See DCN 10–4505.

[29] Martinez-Arroyo, A., Abundes, S., González, M. E., & Rosas, I. (2000). On the Influence of Hot-Water Discharges on Phytoplankton Communities from a Coastal Zone of the Gulf of Mexico. Water, Air & Soil Pollution, 119(1–4), 209–230. See DCN 10–4820.

[30] Smythe, A. G., & Sawyko, P. M. (2000). Field and laboratory evaluations of the effects of 'cold shock' on fish resident in and around a thermal discharge: an overview. Environmental Science & Policy, 3(S1), 225–232. See DCN 10–4887.

[31] Taylor, C. J. L. (2006). The effects of biological fouling control at coastal and estuarine power stations. Marine Pollution Bulletin, 53(1–4), 30–48. See DCN 10–4901.

[32] Hoyal, D. C. J. D., Atkinson, J. F., Depinto, J. V., & Taylor, S. W. (1995). The effect of turbulence on sediment deposition. Journal of Hydraulic Research, 33(3), 349–360. See DCN 10–4797.

[33] Sanford, E. B., Bertness, D., & M. D. Gaines, S. D. (1994). Flow, food supply and acorn barnacle population dynamics. Marine Ecology Progress Series, 104, 49–62. See DCN 10–4882.

[34] Swain, D. P., Sinclair, A. F., & Mark Hanson, J. (2007). Evolutionary response to size-selective mortality in an exploited fish population. Proceedings of the Royal Society B: Biological Sciences, 274(1613), 1015–1022. See DCN 10–4900.

[35] Vanni, M. J., Layne, C. D., & Arnott, S. E. (1997). ''Top-down'' trophic interactions in lakes: effects of fish on nutrient dynamics. Ecology, 78(1), 1–20. See DCN 12–5047.

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ecosystem habitats, such as submerged aquatic vegetation.

The effect of long-term or chronic IM&E may lead to a decrease in ecosystem resistance and resilience [36] (i.e., ability to resist and recover from disturbance, including invasive species). That is, IM&E is likely to reduce the ability of ecosystems to withstand and recover from these ecosystem damages, whether those impacts are due to anthropogenic effects or natural variability.

E. Cumulative Effects of Multiple Facilities

Cumulative effects of CWISs are likely to occur if multiple facilities are located in close proximity and impinge or entrain aquatic organisms within the same source waterbody, watershed system, or along a migratory pathway of a specific species (e.g., striped bass in the Hudson River). EPA analyses show more than 20 percent of all facilities on inland waters withdraw more than 5 percent of the mean annual flow.[37] See TDD Chapter 4.1.3 for detailed discussion. This impact is compounded because more than half of all regulated facilities are located on waterbodies with multiple CWISs. An inspection of the geographic locations of regulated facilities (approximated by CWIS latitude and longitude) shows that facilities in inland settings are more likely to be located in close proximity to other facilities (upstream or downstream) than are facilities in marine and estuarine environments. The cumulative impact of clustered facilities may be significant, due to the concentrated IM&E, combined intake flows, and the potential for other impacts such as thermal discharges.

IV. Summary Description of the Final Rule

Under today's final rule, the owners or operators of existing facilities and new units at existing facilities are subject to BTA standards for impingement mortality and entrainment that are expected to substantially reduce the adverse environmental impacts of cooling water intake structures. Earlier, in Section I, the preamble describes what facilities are subject to the rule. The discussion below presents an overview of the substantive requirements of the rule.

A. BTA Standard for Impingement Mortality for Existing Units at Existing Facilities

The final rule requires that existing facilities subject to this rule must comply with one of the following seven alternatives identified in the national BTA standard for impingement mortality at § 125.94(c) (hereafter, impingement mortality standards):

(1) Operate a closed-cycle recirculating system as defined at § 125.92;

(2) operate a cooling water intake structure that has a maximum through-screen design intake velocity of 0.5 fps;

(3) operate a cooling water intake structure that has a maximum through-screen intake velocity of 0.5 fps;

(4) operate an offshore velocity cap as defined at § 125.92 that is installed before October 14, 2014;

(5) operate a modified traveling screen [38] that the Director determines meets the definition at § 125.92(s) and that the Director determines is the best technology available for impingement reduction;

(6) operate any other combination of technologies, management practices and operational measures that the Director determines is the best technology available for impingement reduction; or

(7) achieve the specified impingement mortality performance standard.

Options (1), (2) and (4) above are essentially pre-approved technologies requiring no demonstration or only a minimal demonstration that the flow reduction and control measures are functioning as EPA envisioned. Options (3), (5) and (6) require more detailed information be submitted to the Director before the Director may specify it as the requirement to control impingement mortality.

In the case of Option (3), which EPA considers to be a streamlined alternative, the facility must submit information to the Director that demonstrates that the maximum intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 feet per second.

In the case of Option (5), the facility must submit a site-specific impingement technology performance optimization study that must include two years of biological sampling demonstrating that the operation of the modified traveling screens has been optimized to minimize impingement mortality. As discussed below, if the facility does not already have this technology installed and chooses this option, the Director may postpone this study till the screens are installed (see VI.G.1.d below).

In the case of Option (6), the facility must submit a site-specific impingement study including two years of biological data collection demonstrating that the operation of the system of technologies, operational measures and best management practices has been optimized to minimize impingement mortality. If this demonstration relies in part on a credit for reductions in the rate of impingement already achieved by measures taken at the facility, an estimate of those reductions and any relevant supporting documentation must be submitted. The estimated reductions in rate of impingement must be based on a comparison of the system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody.

The impingement mortality performance standard in (7) requires that a facility must achieve a 12-month impingement mortality performance of all life stages of fish and shellfish of no more than 24 percent mortality, including latent mortality, for all non-fragile species that are collected or retained in a sieve with maximum opening dimension of 0.56 inches [39] and kept for a holding period of 18 to 96 hours. The Director may, however, prescribe an alternative holding period. The 12-month average of impingement mortality is calculated as the sum of total impingement mortality for the previous 12 months divided by the sum of total impingement for the previous 12 months. A facility must choose to demonstrate compliance with this requirement for the entire facility, or for each individual cooling water intake

[36] Folke, C., Carpenter, S., Walker, B., Scheffer, M., Elmqvist, T., Gunderson, L., & Holling, C. S. (2004). Regime Shifts, Resilience, and Biodiversity in Ecosystem Management . . . Annual Review of Ecology, Evolution, & Systematics, 35(1), 557–581. See DCN 10–4770.

[37] As described in the Phase I proposed rule (65 FR 49060) and the Phase II NODA (66 FR 28853), absent any other controls, withdrawal of a unit volume of water from a waterbody will result in the entrainment of an equivalent unit of aquatic life (such as eggs and larval organisms) suspended in that volume of the water column. Thus, facilities withdrawing greater than 5 percent of the mean annual flow from freshwater rivers and streams may entrain equal proportions of aquatic organisms.

[38] EPA is aware that innovative screen designs are currently being tested that are expected to provide similar or better performance than modified Ristroph traveling screems. Therefore EPA has defined modified traveling screen at 40 CFR 125.92 to mean any traveling water screen that incorporates the specified measures that are protective of fish and shellfish. In this preamble, modified traveling water screen with a fish handling and return system is often referred to more simply a modified traveling screen.

[39] Though less common, the EPA recognizes that ½ by ¼ inch mesh are used in some instances and perform comparably to the ⅜ inch square mesh. Therefore, today's rule allows for facilities to apply a ½ by ¼ inch sieve (diagonal opening of 0.56 inches) or a ⅜ inch sieve (diagonal opening of 0.53 inches) when discerning between impinged and entrained organisms.

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structure. Biological monitoring must be completed at a minimum frequency of monthly.

The owner or operator of an existing facility must meet the impingement mortality requirements as soon as practicable after issuance of a final permit establishing the entrainment requirements under § 125.94(d).

Today's final rule also allows the Director, based on review of site-specific data, to conclude that a de minimis rate of impingement exists and therefore no additional controls are warranted to meet the BTA impingement mortality standard. In addition, today's final rule allows the Director flexibility in determining appropriate site-specific controls that may be less stringent than those found at § 125.94(c)(1) to (7) for existing units at existing facilities operating with a capacity utilization of less than 8 percent averaged over a 24-month block contiguous period. This provision can be found at § 125.94(c)(12). EPA notes that these provisions for impingement mortality would not apply to entrainment because, as discussed in the next section, the requirements for entrainment are established by the Director on a site-specific basis.

B. BTA Standard for Entrainment for Existing Units at Existing Facilities

The final rule establishes the national BTA standard for entrainment at existing units at existing facilities at § 125.94(d) (hereafter, entrainment standards). For such units, the rule does not prescribe a single nationally applicable entrainment performance standard but instead requires that the Director must establish the BTA entrainment requirement for a facility on a site-specific basis. The requirements must reflect the Director's determination of the maximum reduction in entrainment warranted after consideration of all factors relevant to the BTA determination at the site and must include consideration of the specific factors spelled out in § 125.98(f)(2). Facilities that withdraw greater than 125 mgd AIF must develop and submit an Entrainment Characterization Study (§ 122.21(r)(9)), as well as provide other information required at § 122.21(r)(7) and (10), (11), (12) and (13) that must include specified data pertinent to consideration of several of the factors identified in § 125.98(f).

C. BTA Standards for Impingement Mortality and Entrainment for New Units at Existing Facilities

The owner or operator of a new unit at an existing facility must achieve one of two compliance alternatives under the national BTA standards for impingement mortality and entrainment for new units at existing facilities at § 125.94(e) (hereafter, new unit standards).[40] Under the new unit standards, the owner or operator of a facility must reduce AIF at the new unit, at a minimum, to a level commensurate with that which can be attained by the use of a closed-cycle recirculating system as defined at § 125.92(c)(1). The owner or operator of a facility with a cooling water intake structure that supplies cooling water exclusively for operation of a wet or dry cooling tower(s) and that meets the definition of closed-cycle recirculating system at § 125.92(c)(1) meets this new unit standard. Under the alternative new unit standard, the owner or operator of a facility must demonstrate to the Director that it has installed, and will operate and maintain, technological or other control measures that reduce the level of adverse environmental impact from any cooling water intake structure used to supply cooling water to the new unit to a comparable level to that which would be achieved through flow reductions commensurate with the use of a closed-cycle recirculating system. Under this alternative, the owner or operator of a facility must demonstrate entrainment mortality reductions that are equivalent to 90 percent or greater of the reduction that could be achieved through compliance with the first alternative entrainment standard for new units.

The new unit entrainment standards do not apply to certain water withdrawals including (1) cooling water used by manufacturing facilities for contact cooling purposes; (2) portions of those water withdrawals for auxiliary cooling uses totaling less than 2 mgd; (3) any volume of cooling water withdrawals used exclusively for make-up water at existing closed-cycle recirculating systems;[41] and (4) any quantity of emergency back-up water flows. Furthermore, as is the case for existing units, obtaining cooling water from a public water system, using reclaimed water from wastewater treatment plants, or desalination plants, or using recycled process wastewater effluent as cooling water does not constitute use of a cooling water intake structure. The new unit requirements apply only to the volume of cooling water used by the new unit, or to the cooling water intake structures used by the new unit. The new unit requirements do not apply to the rest of the existing facility.

In addition, the Director may establish alternative entrainment requirements for new units when compliance with the new unit entrainment standards would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at issue or will result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement or entrainment, adverse impacts on threatened and endangered species, or significant adverse impacts on local energy markets. Any Director-specified alternative must achieve a level of performance as close as practicable to the requirements of § 125.94(e)(1) or (2).

D. Other Provisions

The final rule contains a number of other provisions related to the BTA impingement and entrainment reduction requirements. For example, the rule also provides that the Director may establish more stringent requirements as BTA if the Director determines that the facility owner or operator's compliance with the requirements otherwise established under the final rule would not meet the requirements of applicable State and Tribal law, including water quality standards. 40 CFR 125.94(i). Today's rule also requires the owner or operator of a facility subject to this subpart to submit and retain permit application and supporting information as specified in § 125.95; monitor for compliance as specified in § 125.96; and report information and data and keep records as specified in § 125.97. Director requirements are specified in § 125.98.

The rule further provides that, in the case of a nuclear facility or a facility constructing or conducting maintenance on nuclear powered vessels of the Armed Services, if the owner or operator of the facility demonstrates to the Director, upon the Director's consultation with the Nuclear Regulatory Commission, the Department of Energy or the Naval Nuclear Propulsion Program, that compliance with this subpart would result in a conflict with a safety requirement established by these entities, the

[40] EPA expects that all new units will comply with these requirements through the installation of a closed-cycle cooling system, which is one of the most effective technologies for reducing impingement and impingement mortality. Therefore, the IM requirements for new units are already addressed by the new unit requirements by virtue of the first compliance alternative of the IM performance standard.

[41] For facilities with a combination of closed-cycle recirculating systems and other cooling water systems, the entrainment mortality standard does not apply to that portion of cooling water withdrawn as make-up water for the closed-cycle recirculating system.

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Director must establish BTA requirements that would not result in a conflict with the Commission's, the Department's or the Naval Nuclear Propulsion Program's safety requirement.

V. Summary of Data Updates and Revisions to the Proposed Rule

This description of revisions to the proposed rule is organized in three sections: Data updates, regulatory approach and compliance, and new units. EPA published two NODAs (Notice of Data Availability) (77 FR 34315, June 11, 2012 and 77 FR 34927, June 12, 2012) based on some comments received on the proposed rule and additional analyses. EPA also took public comment on the information in these notices.

A. Data Updates

On the basis of comments received, additional information made available, and further analyses, EPA revised a number of assumptions used in its assessments for the final rule. These included revisions to the engineering costs of options considered in development of the final rule, the information collection costs, the economic analyses, and the benefits analyses. The revised analyses, along with an explanation of how they affected decision making for this final rule, are discussed below.

1. Impingement Data and Performance Standard

Since publishing the proposal, EPA received a substantial number of comments stating the amount of data to develop the proposed impingement mortality performance standard was too limited. EPA received more than 80 additional documents containing impingement and entrainment data. EPA reviewed these materials and found that many documents did not provide useful data. For example, in some cases, a document did not provide useful information because the only data available were the facility name and raw sampling data for a number of different species of fish or shellfish, or both. In other cases, the documents focused on source water characterization data alone. However, after review, EPA identified more than 40 distinct sets of additional impingement sampling and performance data.

EPA also reevaluated and revised the criteria it used for including impingement mortality study data in the impingement mortality performance standard calculations. In calculating the impingement mortality performance standard of § 125.94(c)(7), EPA applied these revised criteria for acceptable data to both the new data and the earlier data used for proposal. EPA's approach for the final rule is similar to that of the proposal. In order to include data in EPA's calculation, for the proposal, EPA applied the following four criteria. First, the data must be specific to the technology under consideration. Second, impingement mortality must have been reported as an absolute number or a percentage of impinged fish that were killed. Third, the data must reflect that the installed technology was operated under conditions that are representative of actual conditions at a facility, and fourth, the reported values must be actual measurements. EPA based the proposed performance standard on the performance of modified traveling screens with a fish return system using a limited definition of the control technology.

In its reevaluation and based on comments, EPA decided to revise some of the criteria and add two new ones. In some cases, the effect of these changes is to relax the criteria and in others, to impose more restrictive criteria. First, all impingement data must be for non-fragile species (including shellfish). Second, the data must be representative of annual mortality data for purposes of deriving an annual performance standard. EPA notes that in contrast to the proposed rule, the permit application does not require submission of the proposed list of ''species of concern.'' EPA found that the term ''species of concern'' was similar to terms used in the context of T&E (threatened and endangered) species, and may further cause confusion over existing Services or State requirements for such species. Further, despite EPA's efforts to distinguish between species of concern and RIS (representative indicator species) in the NODA (77 FR 34325, June 11, 2012), EPA found that many commenters were still confused by the language. Instead, EPA is adopting the term ''fragile species'' and using the term exactly as it is used with the impingement mortality data and criteria used in calculating the impingement mortality performance standard of the rule. EPA included a definition for ''fragile species'' at § 125.92(m), as a species of fish or shellfish that has an impingement survival rate of less than 30 percent. EPA took this approach to ensure that a facility's performance in reducing impingement mortality as demonstrated by collecting biological data would reflect only the effects of its improvements to the CWIS technology, and not be confounded by effects of data collection that are not caused by impingement.

EPA also relaxed the holding time criteria as a result of reevaluating the range of acceptable impingement mortality holding times, which at proposal was limited to 24 to 48 hours. After evaluating the data, EPA concluded that a range of holding times of 18 to 96 hours was acceptable for inclusion in the development of a performance standard because commenters had provided documentation showing that the actual time period typically had little effect on IM rates. At proposal, EPA counted all fish that died at any time during the holding period. For the final rule being promulgated today, EPA excludes those that were dead at time zero because such counts measured immediate deaths and not those organisms that were mortally harmed as a result of impingement. These counts also might reflect already injured, nearly dead, or already dead fish (''naturally moribund'') that were impinged by the screen. As a consequence of relaxing the holding times and other requirements, EPA based the performance standard on a larger set of data, with broader geographic representation. (For more information, see DCN 12–6703.) The rationale for these revisions to the data acceptance criteria are described in further detail in the TDD, Chapter 11. Using the revised criteria, EPA reviewed the data in each of the impingement mortality studies for potential inclusion in EPA's evaluation of an impingement mortality performance standard. These changes resulted in an increase in the number of facility data sets acceptable for determining the impingement mortality performance standard, from four data sets at three facilities at proposal to 26 data sets at 17 facilities today. As a result, the 12-month average impingement mortality performance standard of all life stages of fish and shellfish was revised from no more than 12 percent to no more than 24 percent mortality, including latent mortality, for each non-fragile species that is collected or retained in a sieve with maximum opening dimension of 0.56 inches and kept for a holding period of 18 to 96 hours. The revised performance standard and data evaluation criteria are discussed in detail in Section VI and Chapter 11 of the TDD.

EPA also reevaluated its approach to compliance monitoring for the impingement mortality performance standard. In particular, EPA considered the costs and burden of frequent biological monitoring for those technologies that, according to EPA's record, perform equal to or better than

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the IM performance standard. As proposed, all facilities would have conducted weekly biological monitoring in perpetuity irrespective of the compliance approach or technologies selected. EPA agrees with comments that this may be unnecessarily burdensome and of limited value for those technologies for which the potential performance is well documented. As such, today's final rule includes seven compliance alternatives, only one of which requires biological compliance monitoring.

EPA notes, however, that a facility relying in part on a credit for reductions in impingement mortality already obtained at the facility (§ 125.94(c)(6)) must gather biological data at a minimum frequency of monthly for a period of two years in order to calculate their 12-month average impingement mortality. Further, a facility choosing to comply using the impingement mortality performance standard (§ 125.94(c)(7)), must conduct biological monitoring at a frequency of at least monthly in order to calculate its 12-month average impingement mortality. The 12-month average is calculated as the sum of total impingement mortality for the previous 12 months divided by the sum of total impingement for the previous 12 months. EPA is requiring that a facility choose to either demonstrate compliance with this requirement for the entire facility, or for each individual cooling water intake structure. The EPA expects that as the performance of the technology is demonstrated by the facility, the Director could reduce the frequency of biological compliance monitoring. Further, prior to a subsequent permit application, a facility could collect sufficient performance data to demonstrate to the satisfaction of the Director that its ''systems of technologies'' compliance alternative is BTA at that facility.

2. Technology Costs

Since publishing the proposal, EPA received a number of public comments from industry stating that EPA had underestimated the costs of modified traveling screens with fish returns. EPA used new information to revise the compliance cost estimates (including the methodology used for technology assignment) and the capital costs for several compliance technologies, including those used as the primary basis for the final rule. Those changes include the following:

- In response to comments challenging EPA's assumption that modified traveling screens were available at most facilities, EPA changed the assignment of the modified traveling cost module [42] so as to apply this only where the existing intake for the model facility intake employed traveling screens. As a result, a number of intakes, such as those that use passive screens (e.g., fixed screens), were assigned higher cost technologies such as larger intakes or wedgewire screens with through-screen design velocities of 0.5 fps.
- Because EPA has clarified that properly operated closed-cycle recirculating systems is one of the compliance alternatives for impingement mortality, those intakes with existing closed-cycle cooling no longer receive additional impingement technology costs.
- At proposal, the design of the larger intake module was based on a through-screen velocity of 1.0 fps and, therefore, was not consistent with the low velocity compliance alternatives. To ensure that this technology will be consistent at all locations, the through-screen design velocity for the larger intake was changed to a maximum of 0.5 fps, resulting in a substantial increase in capital and operational and maintenance costs.
- EPA received a number of comments noting that fish returns might be difficult to install at some intakes. EPA reviewed the fish return cost component of the modified traveling screen module and concluded that EPA's costs represented an ''easy'' installation rather than an average of both easy and more difficult installation costs. To account for a wider range of fish return costs that includes those with higher costs, EPA increased the capital costs of the fish return component and included additional costs for those with particularly difficult circumstances such as very long intake canals and submerged offshore intakes. For a detailed discussion, see Chapter 8 of the TDD.
- EPA received a number of comments stating that it had underestimated capital costs for modified traveling screens. During site visits to several facilities, EPA obtained actual traveling screen replacement costs. EPA compared its estimates to actual reported replacement costs and vendor-supplied data and concluded that the capital costs were underestimated by about 20 percent. Therefore, EPA increased the capital costs of modified traveling screens by 20 percent.

These changes to the engineering costs result in a 24 percent increase in capital and O&M costs. The revised costing assumptions are discussed in further detail in Chapter 8 of the TDD.

3. Monitoring Costs for Impingement Mortality

Many commenters expressed concern that requirements for monitoring for the impingement mortality performance standard were excessive. Of particular concern were the long-term costs for impingement mortality monitoring at facilities that would be relying on either closed-cycle cooling or an intake velocity less than or equal to 0.5 fps through-screen design velocity. The final rule includes seven compliance alternatives for the impingement standard. One of these alternative provides for reduced monitoring requirements for facilities employing modified traveling screens. This alternative is available if the facility has demonstrated the technology is optimized to minimize impingement mortality of all non-fragile species. Under this approach, EPA requires the facility to provide site-specific performance data to identify the operational conditions that will ensure that the technology is being operated optimally. Once these operational conditions have been identified, the Director must include in the permit those operational measures and best management practices identified in the study and deemed as necessary by the Director to ensure proper operation of the modified traveling screens. EPA also clarified in the rule that compliance monitoring and reporting requirements for facilities that comply with the impingement mortality standard by employing one of the pre-approved or streamlined IM compliance alternatives will be largely limited to information that ensures proper operation of the installed control technology. EPA estimates that this alternative approach will reduce annual monitoring and reporting costs from approximately $47 million under the proposed rule to approximately $27 million under the final rule.

4. Benefits and Willingness To Pay Survey

EPA received a number of comments on the proposed rule and NODA addressing the use of stated preference surveys to determine the public's willingness-to-pay for benefits associated with the rule. EPA conducted a stated preference survey to calculate benefits associated with minimizing

[42] EPA used a model facility approach to develop compliance technology costs where different sets of compliance technology cost algorithms called modules were assigned to individual model facility intakes on the basis of site-specific conditions. For a more detailed discussion, see the TDD Chapter 8.

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adverse impacts to aquatic ecosystems from cooling water intakes. For some commenters, the use of stated preference surveys to evaluate benefits remains controversial, and they objected to using such surveys. Other commenters acknowledge the decades of technical development and improvement of these methods and support using stated preference surveys. Based on consideration of public comment, EPA decided not to employ the survey results for purposes of decision-making in this rule, or include them in assessing the total benefits of the rule. The rule does not require State Directors to require facility owners or operators to conduct or submit a willingness to pay survey to assess benefits.

B. Regulatory Approach and Compliance

1. Regulatory Approach

EPA has largely adopted the regulatory approach of the proposed rule with several changes regarding compliance, particularly with respect to the impingement mortality requirements. These changes clarify elements of the rule (as discussed in the NODAs) about which commenters expressed uncertainty and provide additional flexibility to regulated facilities in meeting the rule's impingement mortality standard.

EPA received some comments questioning whether specific provisions apply to the entire facility or to individual intakes. To clarify this issue, EPA modified the rule language so as to state clearly that a facility with multiple intakes must decide whether it will adopt a single compliance strategy for impingement mortality for the entire facility or adopt an intake-specific compliance strategy at each cooling water intake. Thus, facilities may select different compliance strategies for different intakes, providing flexibility at facilities with multiple intakes. Regardless of which impingement compliance approach a facility chooses (single strategy for entire facility or different strategies for different intakes), if the facility chooses to comply with the impingement standard by operating at a maximum through-screen velocity of 0.5 feet per second, the facility must measure and comply with the low velocity compliance alternative of 0.5 fps on an individual intake basis.

a. Impingement Mortality Standards

EPA received a substantial number of comments requesting greater flexibility and clarification regarding compliance with the impingement mortality standards, including suggestions that (1) impingement requirements be addressed on a site-specific basis; (2) certain technologies should be pre-approved; (3) credit should be given for existing technologies and operating conditions; and (4) combinations of technologies be allowed. EPA has concluded that low-cost technologies for impingement mortality reduction are effective, widely available, feasible, and demonstrated for facilities nationally and thus, a completely site-specific approach is not appropriate. However, recognizing that for some sites technologies other than modified traveling screens may allow a facility to achieve the same level of performance, EPA has included compliance options that provide for more flexibility and allow consideration of the performance of combinations of technologies and operating conditions. Some of the more significant changes include the following:

- *Compliant technologies*—EPA has concluded that employing certain technologies will meet or exceed the requirement of the impingement mortality standard, provided they meet certain design and operational criteria. These pre-approved and streamlined technologies include a closed-cycle recirculating system, existing offshore velocity cap, and maximum design intake velocity of 0.5 fps. Associated with these compliance options are reduced monitoring requirements.

  ○ *Closed-Cycle Cooling*—EPA has concluded that a fully closed-cycle recirculating system as defined at § 125.92(c) (and that is properly operated and maintained) achieves the impingement mortality performance standard. Even after retrofitting a facility to be closed-cycle, it may still be possible to withdraw and discharge cooling water at rates associated with once-through cooling. Existing facilities that retrofit to closed-cycle cooling often do so without modifying or replacing their condenser to optimize it for closed-cycle operation. In such cases, the facility has an incentive to operate its system in a once-through cooling mode, to minimize chemical costs or avoid a turbine backpressure constraint. EPA has concluded that it is not appropriate to add conditions to the definition of closed-cycle cooling because water may be withdrawn for purposes of replenishing losses to a closed-cycle recirculating system other than those due to blowdown, drift, and evaporation from the cooling system. However, the final rule provides the Director the discretion to determine whether the operation of a cooling system minimizes the make-up and blowdown flows withdrawn, consistent with the definition of a closed-cycle recirculating system (40 CFR 125.92(c)).

  ○ *Existing Offshore Velocity Caps*—The record indicates that an existing offshore velocity cap as defined at § 125.92(v) also achieves the necessary reductions in impingement mortality and thus meets the IM standard. Data in the record concerning existing velocity caps show that a velocity cap alone is insufficient, but data on existing offshore velocity caps shows that a velocity cap in combination with their current offshore locations meet EPA's BTA standard for impingement mortality. EPA has determined that new offshore velocity caps could comply using the combination of technologies approach in § 125.94(c)(6). The offshore component likely makes the velocity cap technology unavailable except to facilities in marine waters and certain Great Lakes locations; therefore, the technology alone is not BTA.

  ○ *Through-Screen Velocity*—EPA has clarified that compliance with a 0.5 fps intake velocity achieves the IM standards. EPA's record shows an intake velocity of 0.5 fps or lower provides similar or greater reductions in impingement, and therefore impingement mortality, than modified traveling screens—the technology forming the basis for the numeric impingement mortality performance standard that is the goal for all facilities. There are two ways to demonstrate compliance using intake velocity. First, an intake with a maximum design intake velocity less than or equal to 0.5 fps is pre-approved BTA for impingement mortality and does not require further monitoring. Alternatively, under a streamlined option, the facility may demonstrate to the Director that the facility meets the velocity requirement through monitoring of the actual intake velocity. Screen velocity can be monitored by direct measurement or by calculation using the volumetric actual intake flow and source water surface elevation.

- *Modified Traveling Screens*—A facility must operate modified traveling screens [43] that the Director determines meets the definition at § 125.92(s). Facilities will demonstrate that they have optimized performance of their traveling screen to minimize IM.

[43] While rotary screens are technically not modified traveling screens, the regulation at § 125.92(s) defines modified traveling screens to include traveling water screens that incorporate measures protective of fish and shellfish. EPA has thus provided the flexibility for other types of active screens that achieve the same or better performance than modified traveling screens.

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• *Systems of Technologies to Meet the IM Standard*—EPA received a substantial number of comments asking whether previously installed technologies or various combinations of technologies and operating conditions could also meet the BTA standard for impingement mortality. For example, some technologies, such as louvers, reduce the rate of impingement, but the effect on overall impingement mortality reduction cannot easily be measured and would not appear in biological sampling of the technology. In EPA's view, the Director should take into account the reduction in impingement—for example, that associated with such technologies as louvers or behavioral deterrents, or due to intake location—when determining permit conditions to include in the facility's permit in order for a combination of technologies to achieve the required impingement mortality standards. Thus, the facility should obtain credit toward the impingement mortality standard for such reductions in the rate of impingement. A number of the flexibilities above were described in the June 11, 2012 NODA, and EPA has included a provision to allow additional flexibility in achieving compliance through the use of a combination of technologies and operating conditions. A facility may use a system of technologies, management practices and operational measures to achieve the impingement mortality standard, including, for example, flow reductions, seasonal operation, unit closures, credit for intake location, behavioral deterrent systems, and other technologies and operational measures. The Director must determine, based on a demonstration by the facility to the Director, that the system of technologies or operational measures, in combination, have been optimized to minimize impingement mortality of all non-fragile species. The Director may require additional operational measures, best management practices, and monitoring as part of the demonstration. In addition, the facility's permit must include conditions to ensure that the facility operates its cooling water intake structures in a manner consistent with the conditions and measures identified in its demonstration to the Director.

• *Numeric IM Performance Standard*—As a practical matter, EPA expects that very few facilities will choose to comply with the numeric impingement mortality performance standard. Those facilities that choose to comply in this way will need to demonstrate to the Director how the technology the facility is implementing enables the facility to meet the impingement mortality standard. The numeric standard provides a pathway to compliance for innovative technologies that may be developed in the future.

EPA also received many comments stating that barrier nets were both unnecessary and might be unavailable in many locations. Because EPA's revised impingement data set had sufficient data to characterize shellfish impingement, EPA has eliminated the barrier net requirement in the final rule. See Section VI for more information.

b. Definition of Closed-Cycle Cooling System

In the final rule, EPA revised the definition of a closed-cycle recirculating system to provide additional flexibility for the Director in determining which closed-cycle cooling systems comply with the IM standards. The proposed rule's definition of ''closed-cycle recirculating systems'' included, as elements of a properly operated closed-cycle system performance, requirements generally expressed in terms of cycles of concentration (COC) or percentage flow reduction relative to a once-through cooling system. Cycles of concentration represents the accumulation of dissolved minerals in the recirculated cooling water. Discharge of a portion of the water (called ''blowdown'') is used to control the buildup of these minerals. COC is a measure of how concentrated are chlorides in recirculated water relative to make-up water, and thus how well a system recycles intake water before replacing it with new withdrawals. This is not to be confused with cycles of flow, as some commenters appeared to do.

Cycles of concentration can be measured as the ratio of chloride levels in the recirculated water or blowdown relative to the chloride levels in the source water, or makeup water. Some commenters stated that, while they have been operating as closed-cycle units for many years, they were concerned that their facilities would not be ''closed-cycle recirculating systems'' under the proposed definition because they would not achieve the required COC. EPA has found the concentration cycles in the majority of cooling towers usually range from 3 to 6 at power plants, and can often exceed 9 at manufacturing facilities. However, EPA recognizes that many manufacturers have complex water balances, and calculating a specific flow reduction attributable to cooling water use could be difficult and time consuming. In such cases, many manufacturers could far more readily calculate the cycles of concentration of particular unit operations, and could therefore show those unit operations that use cooling water meet the conditions for closed-cycle cooling. EPA found in site visits many complex manufacturing facilities already have this capability, and have achieved very high COC. Likewise, power plants may find it much easier to measure flow than cycles of concentration. Accordingly, EPA's proposed rule attempted to recognize performance using either metric. EPA expects most power generators would use percentage flow reduction to demonstrate they are closed-cycle, and expects most manufacturing facilities would use COC for those units that utilize water for cooling purposes. Increasing the amount of minerals present in the water by cycling can make water less aggressive to piping; however, EPA is also aware that excessive levels of minerals (such as found in certain source waters, most notably those with higher salinity) can cause scaling problems, leading to different levels of both metrics for freshwater and saltwater facilities.

EPA carefully considered these issues and concluded that the most important aspect of the definition of a properly operated closed-cycle cooling system is that the makeup flow be minimized. Thus EPA has removed the numeric levels of the metrics as a threshold, while retaining the minimized makeup flow aspect of the definition. As an example, in the case of a facility that uses make-up water from a freshwater source, a Director may determine that a closed-cycle recirculating system can generally be deemed to minimize make-up and blowdown flows if it reduces actual intake flows (AIF) by 97.5 percent as compared to a once-through cooling system or if its cooling tower is operated at a minimum cycles of concentration of 3.0. And likewise, in the case of a facility that uses make-up water from a saltwater, brackish, or other source with a salinity of greater than 0.5 parts per thousand, a Director may determine that a closed-cycle recirculating system can generally be deemed to minimize make-up and blowdown flows if it reduces actual intake flows (AIF) by 94.9 percent as compared to a once-through cooling system or if its cooling tower is operated at a minimum cycles of concentration of 1.5. These reductions and cycles of concentration are illustrative. A Director may determine that other levels near these numbers could also constitute a closed-cycle recirculating system. The final rule further recognizes that in certain unavoidable circumstances, these levels for COC or percent flow reduction might not be achievable at all facilities. Such circumstances could

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include situations where water quality-based discharge limits might limit the concentration of a pollutant that is not readily treatable in the cooling tower blowdown or situations where varying source water quality could lead to unavoidable problems concerning scale formation, solids buildup, corrosion, or media fouling. Such facilities should demonstrate these circumstances to their Director and indicate the measures they have taken to minimize makeup flows. The Director will retain the discretion to conclude that the particular facility employs a closed-cycle recirculating system when the benchmarks are not met.

In cases where the Director will make a determination as to whether the facility's cooling system meets the definition of a closed-cycle recirculating system, EPA's intent is that the withdrawal of small amounts of service water (for uses such as fire suppression, potable water, screenwash water, vehicle wash water, and such) do not preclude consideration of the system as closed-cycle. To avoid misuse of this provision, the Director will make the final determination.

Finally, EPA data show more than 50 facilities have cooling systems that include impoundments. In some cases, the cooling systems that include impoundments were created in the waters of the U.S., in whole or in part, or were created in uplands but withdraw make-up water from waters of the U.S. These cooling systems may perform like a closed-cycle recirculating system. EPA has clarified at 40 CFR 125.92(c)(2) that a cooling system that includes an impoundment lawfully created in the waters of the U.S for the purpose of cooling may be considered a closed-cycle recirculating system. As with other closed-cycle recirculating systems, the Director will determine whether the impoundment minimizes the withdrawal of water for cooling purposes and therefore meets the definition of a closed-cycle recirculating system. See Section VI for further discussion.

c. Entrapment

The proposed rule included a prohibition on trapping organisms in an intake structure with no viable escape route. Many commenters expressed concern that the entrapment requirements were not well defined and would require costly technologies not considered in EPA's cost estimates. Moreover, in the commenters' view, the requirements could be difficult to comply with, particularly where cooling systems employ impoundments or basins downstream of the initial intake structure. EPA agrees that in some cases, such as where a canal or basin for maintaining consistent water levels is located behind the CWIS, that the proposed entrapment requirement could require additional controls such as additional fish returns that are not, in all cases, feasible. For example, EPA found in site visits that the forebay may be located more than a mile from the CWIS, and a fish return in that situation would not have been feasible. The final rule deleted the requirement that prohibited entrapment. In the final rule, facilities would account for all impinged fish and shellfish when conducting their two year performance study. To the extent entrapment of shellfish poses a concern, the Director may establish additional measures, such as seasonal deployment of barrier nets, under § 125.94(c)(8).

d. Requirements for Threatened and Endangered Species

EPA consulted with the Fish and Wildlife Service and National Marine Fisheries Service and EPA made a number of adjustments to the rule to protect threatened and endangered species and designated critical habitat as a result of the consultation; the protections were included to insure that the rule is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat. To be clear, the ESA provisions of the rule extend to all listed T&E species, not just fish and shellfish. See Section VIII.K for a summary of these provisions.

2. Compliance Timelines for Impingement Mortality and Entrainment Requirements

At proposal, compliance deadlines for impingement mortality and entrainment requirements were set separately. Facilities would have been required to meet impingement mortality reduction requirements as soon as possible, but no more than eight years after the effective date of the rule. Compliance with entrainment reduction requirements would have been set by the Director. Many commenters expressed concern that the compliance timeline for the impingement mortality and entrainment requirements should be harmonized to prevent a facility from having to install a technology to comply with impingement mortality requirements, only to be required at a later date to install an entrainment reduction technology that effectively renders the investment in the impingement mortality technology obsolete or worthless.

EPA agrees that facilities required to install both impingement and entrainment compliance technologies will benefit from reduced compliance costs if the compliance scheduling is coordinated. EPA also agrees that requiring more timely decisions on entrainment requirements than anticipated at proposal will facilitate these cost savings without sacrificing fish protection. In some cases, impingement compliance can be attained with entrainment technologies. For example, the Director may determine that the installation of modified fine-mesh traveling screens and narrow-slot wedgewire screens will achieve the impingement mortality standard and further, that this same equipment represents, on a site-specific basis, BTA entrainment control. If the compliance schedule is not harmonized, it is possible that a facility could install (at significant cost) coarse-mesh traveling screens that it might have to later retrofit with fine-mesh panels. It is also possible that a facility could make modifications necessary to attain a 0.5-fps through-screen velocity to meet the IM standards and later have closed-cycle cooling identified as BTA for entrainment, thereby making the intake modifications for impingement control unnecessary.

To address this issue in the final rule, EPA revised the compliance requirements so that the Director is required first to establish entrainment requirements under § 125.94(b)(1) in the final permit. The facility will then be required to comply with the impingement mortality standard in § 125.94(c) as soon as practicable thereafter. See Section VIII on implementation for more detailed discussion.

Because an entrainment requirement could require controls that take many years to design, finance and construct, the Director may establish interim milestones related to meeting the final requirements to ensure that the facility is making progress.

C. New Units

EPA has revised the definition of new units to mean a stand-alone unit at an existing facility the construction of which is commenced after the effective date of today's final rule; consists of only a stand-alone unit constructed at an existing facility; and that does not otherwise meet the definition of a new facility at § 125.83. A stand-alone unit is a new, separate unit that is constructed at an existing facility. New unit includes stand-alone units that are added to a facility for purposes of the same general industrial operation as the existing

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facility. A new unit may have its own dedicated cooling water intake structure, or may use an existing or modified cooling water intake structure.

VI. Basis for the Final Regulation

In response to the Supreme Court's decision in *Entergy Corp.* v. *Riverkeeper, Inc. et al.* in April 2009, EPA has reevaluated the requirements for existing facilities under CWA section 316(b). As discussed above, EPA collected additional data and information to update its assessment of the efficacy of various technological measures for reducing IM&E and analyses prepared for the earlier rule-making efforts. EPA's additional technical rigor provided a strengthened analysis of different technologies for reducing IM and their effectiveness. As a result of its revised assessments and further consideration of the factors affecting the availability of different technology in a wide range of settings, EPA has decided not to re-promulgate requirements for existing facilities that mirror those of the final Phase II rule. Further, EPA is adopting, for the reasons explained in detail below, a new framework. In addition, as previously noted, EPA decided to address all existing facilities subject to section 316(b) in this rule (i.e., both those subject to the Phase II rule and some of those subject to the Phase III rule). For a brief description of the final rule, see Section IV.

A. EPA's Approach to BTA

CWA section 316(b) requires EPA to establish standards for cooling water intake structures that reflect the ''best technology available for minimizing adverse environmental impact.'' As explained above, the statute is silent with respect to the factors that EPA should consider in determining BTA, but courts have held that section 316(b)'s reference to CWA sections 301 and 306 is an invitation for EPA to look to the factors [44] considered in those sections in establishing standards for section 316(b).

But EPA, when considering such factors, is not bound to evaluate these in precisely the same way it considers them in establishing effluent limitations guidelines under CWA section 304. As the Supreme Court noted, given the absence of any factors specified in section 316(b), EPA has much more discretion in its standard setting under section 316(b) than under the effluent guidelines provisions. Therefore, the statute vests EPA with broad discretion in determining what is the ''best'' technology that is ''available'' for minimizing adverse environmental impact. As the Supreme Court has further explained, under section 316(b), the ''best'' technology ''available'' may reflect a consideration of a number of factors and ''best'' does not necessarily mean the technology that achieves the greatest reduction in environmental harm that the regulated universe can afford. Rather, the ''best'' (or ''most advantageous,'' in the court's words) technology may represent a technology that most efficiently produces the reductions in harm.

EPA interprets section 316(b) to require the Agency to establish a standard that will best minimize impingement and entrainment—the main adverse effects of cooling water intake structures not otherwise addressed by the other sections of the CWA (e.g., thermal discharges). In EPA's view, several important considerations underpin its decision. First, its BTA determination should be consistent with, and reflective of, the goals of CWA section 101: ''to restore and maintain the physical, chemical, and biological integrity of the Nation's waters,'' with the interim goal of ''water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for recreation in and on the water.''

Second, E.O. 13563 directs EPA and other Federal agencies to identify and use the best, most innovative and least burdensome tools for achieving regulatory ends. In its regulatory actions, agencies ''must take into account benefits and cost, both quantitative and qualitative,'' and to the extent permitted by law, only promulgate regulations that are based on ''a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify)'' (see section 1(b)(1)). In selecting a regulatory approach, agencies must tailor regulations to impose the least burden on society and, in choosing among regulatory alternatives, select ''those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity)'' to the extent permitted by law. 76 FR 3821 (January 21, 2011). Because the Supreme Court has concluded that the CWA authorizes EPA to consider costs and benefits in its BTA determination, EPA has consequently considered costs and benefits in this final rule as directed by the President. In accord with E.O. 13563, EPA has concluded that the benefits of the final rule justify its costs. For additional discussion, see Section VI below.

Consideration of benefits is complicated by the debate about the tools and data that would permit a complete expression of ecological benefits in monetized terms. EPA has, however, used the best available science regarding widely accepted tools and data to monetize the benefits of the various options in four major categories: recreational fishing, commercial fishing, nonuse benefits, and benefits to threatened and endangered species (see Section X below). EPA has concluded that the benefits estimated for the first two categories are generally complete, while the benefits estimated for the latter two categories are far from being complete for a number of reasons. For example, the nonuse benefits transfer was based on a species that represents less than one percent of adverse environmental impacts. EPA is continuing to refine its tools to develop a more complete analysis concerning benefits for future application.

In selecting the ''best'' technology available for minimizing adverse environmental impact, EPA looked at a number of factors. As discussed previously, EPA's initial approach to 316(b) standard setting was similar to one it follows in considering a technology-based rule under sections 301, 304, and 306. EPA first considered the availability and feasibility of various technologies, and then evaluated costs associated with these technologies (including potential costs to facilities and households), and their economic impacts. EPA also reviewed the effectiveness of these technologies in reducing impingement mortality and entrainment. Further, EPA also considered additional factors set out in CWA section 304(b), including location, age, size, and type of facility. In addition, EPA considered the non-water quality environmental impacts of different technologies on energy production and availability, electricity reliability, and potential adverse environmental effects that could arise from the use of the different technologies evaluated.

As a result of this thorough evaluation, in the case of the BTA standard for impingement mortality, EPA based the standard on performance of well-operated modified traveling screens with a fish handling and return system as defined more specifically by the rule. Under the BTA IM standard, a facility has a number of options for

[44] The factors specifically delineated in CWA sections 301 and 306 include cost of the technology, taking into account the age of the equipment and facilities, process employed, engineering aspects associated with a particular technology, process changes and non-water quality environmental impact (including energy requirements).

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compliance. In the case of the BTA standard for entrainment, on the other hand, EPA could not identify one technology that represented BTA for existing facilities on a national basis.

B. Overview of Final Rule Requirements

As noted, EPA concluded that the best technology available for minimizing impingement mortality was ''modified traveling screens,'' as more specifically defined in the rule. The BTA Impingement Mortality Standard includes seven technology options for complying with the standard whose performance is equivalent to, or better performing than modified traveling screens. First, the rule identifies four technologies (closed-cycle recirculating systems, reduced design intake velocity, reduced actual intake velocity, and existing offshore velocity caps) that reduce impingement mortality as well or better than modified traveling screens, and therefore will generally comply with the BTA Impingement Mortality Standard of today's final rule.

The rule also provides that, if the Director determines that modified traveling screens are insufficient to protect shellfish, the Director may establish additional measures under § 125.94(c)(8) such as seasonal deployment of barrier nets, or if modified traveling screens [45] are insufficient to protect other species, the Director may establish additional protective measures under § 125.94(c)(9). In addition, the rule provides in § 125.94(g) that the Director may establish additional control measures and monitoring or reporting requirements in the permit in order to protect Federally-listed threatened and endangered species and designated critical habitat. The Director may include such conditions that are designed to minimize incidental take, reduce or remove more than minor detrimental effects to Federally-listed species and designated critical habitat or avoid jeopardizing Federally-listed species and or destroying or adversely modifying designated critical habitat (e.g., prey base).

Next, the final rule provides an option that allows a facility to demonstrate to its permitting authority that it has installed modified traveling screens—the technology EPA identified as the basis for the BTA impingement mortality standard—and to provide data on the performance of its screens. The facility must demonstrate that its modified traveling screens are consistent with EPA's definition and demonstrate through an impingement technology performance optimization study that its screens have been optimized to minimize impingement mortality. After consideration of the information provided, the permitting authority will determine whether the technology is the best technology available for impingement mortality reduction at the site and include permit conditions to ensure optimal performance of the screens. In other words, the owner or operator of a facility will comply with the BTA standard for IM at § 125.94(c)(5) if that facility uses modified traveling screens as defined at § 125.92(s), and operates in accordance with the permit conditions established by the Director that ensure the technology will perform as demonstrated. As noted above, in certain circumstances, under §§ 125.94(c)(8), (9) and 125.94(g), the Director may require additional protective measures.

As stated in the June 11, 2012 NODA, EPA does not intend for facilities to install closed-cycle cooling solely for the purpose of meeting the IM requirements. In fact, EPA expects all facilities could comply with IM requirements without relying on retrofitting to closed-cycle cooling (see Exhibit VIII–1, showing expected compliance alternative based on technologies in place today). If a facility chooses to comply with the BTA IM standard by installing and operating traveling screens, the screens must meet the definition of modified traveling screens provided at § 125.92(s). These may include, for example, modified Ristroph screens with a fish handling and return system, dual flow screens with smooth mesh, and rotary screens with fish returns such as vacuum pumps. EPA based the regulatory definition on the commonly found features of modified traveling screens used in developing the BTA impingement mortality standard.

In addition, the final rule also provides a compliance option that would allow facilities the option of demonstrating to the Director on a site-specific basis, similar to the showing for modified traveling screens, that a system or combination of technical and operational measures will achieve the BTA standard for impingement mortality at a particular site. Using a combination of technical and operational measures as the basis for demonstrating compliance allows facilities the opportunity to take credit for intake location, flow reduction, or other measures already employed to reduce the rate of impingement. Further, the combination of technical and operational measures provides the flexibility to use a system of approaches to reducing impingement and impingement mortality. This may include technologies that were not found to reduce impingement consistently or in all circumstances, but that on a site-specific basis have been demonstrated to provide a high level of performance. For example, a facility might employ light and sound to induce an avoidance response from certain species. This might not alone address impingement mortality for all non-fragile species at the intake, therefore additional measures (intake location, barrier nets, etc.) would also be applied, to minimize the rate of impingement or impingement mortality.

For both the screens and system of technologies, a two year study must be completed in which biological data collection is used to make site-specific adjustments to screens or the combination of technologies in order to optimize performance at that facility. Those optimal operating parameters then become permit conditions. For facilities that have already installed traveling screens or the technologies associated with the system approach, EPA has combined the two year biological study with the other permit application and rule requirements for biological data collection, including the Source Water Baseline Biological Characterization Data. In this manner, EPA is establishing a consistent set of biological study requirements, with an overall reduction in the burden of the required level of biological monitoring.

Lastly, a facility may choose to comply with the numerical impingement mortality performance standard that was established based on the BTA technology. If a facility chooses this compliance option, it must conduct periodic monitoring to demonstrate compliance. Under this last compliance option, a facility could implement innovative technologies to address impingement mortality and subsequently demonstrate that their performance is as good as, or better than, a modified traveling screen with fish handling and return system. EPA envisions that after a sufficient demonstration period of a technology's performance, the facility will be able to qualify its operation under the previous option.

For entrainment, on the other hand, EPA could not identify one technology that represented BTA for existing facilities on a national basis, for the reasons explained in detail below. Instead, the national BTA entrainment standards for existing facilities establishes a detailed regulatory framework for the determination of BTA

[45] Or any of the IM compliance alternatives.

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entrainment requirements by the permitting authority on a site-specific basis.

While site-specific permit requirements are not new, what is different about this approach from the current requirement for permits to include 316(b) conditions is that for the first time, EPA is establishing a detailed specific framework for determining BTA entrainment control requirements. Thus, the rule identifies what information must be submitted in the permit application, prescribes procedures that the Director must follow in decision making and factors that must be considered in determining what entrainment controls and associated requirements are BTA on a site-specific basis.

As previously noted, EPA looked at a number of factors in considering what national entrainment standard it should adopt. As discussed in detail in the following section, EPA identified only one high performing technology as a potential BTA candidate for entrainment: closed-cycle recirculating systems as defined at § 125.92(c)(1). While there are other technologies for entrainment that are available or demonstrated, they are not uniformly high performing technologies. See TDD Chapter 6 for more information regarding the lack of intermediate performing technologies for entrainment. EPA has identified the following specific factors as the key elements in its decision not to prescribe this technology as the basis for a national BTA standard for entrainment: land availability, air emissions, and remaining useful plant life. How these factors dictated EPA's decision is discussed below.

For new units at existing facilities, EPA has established BTA requirements to minimize impingement mortality and entrainment, based on flow reduction commensurate with closed-cycle cooling. The rest of this section describes in detail the above considerations.

C. Technologies Considered To Minimize Impingement and Entrainment

As described in Chapter 4 of the TDD, power plants and manufacturers withdraw large volumes of cooling water daily. Cooling water withdrawals are responsible for over half of surface water withdrawals for all uses in the United States, including agriculture and municipal uses. The purpose of cooling water withdrawals is to dissipate that portion of the heat that is a by-product of industrial processes that facilities have not harnessed to a productive end and therefore view as waste heat.

The majority of environmental impacts associated with intake structures are caused by water withdrawals that ultimately result in the loss of aquatic organisms. These losses might be from impingement, entrainment, or both. Impingement occurs when organisms are trapped against the outer part of a screening device of an intake structure.[46] The force of the intake water traps the organisms against the screen and they are unable to escape. Not all organisms in the incoming water are impinged, however. Some might pass through the screening device and travel through the entire cooling system, including the pumps, condenser or heat exchanger tubes, and discharge pipes. This is referred to as entrainment. Various factors lead to the susceptibility of an organism to impingement or entrainment. For more detailed discussion of impingement and entrainment and the associated mortality and other effects, see Section III above.

For purposes of this rule, EPA is adopting the following conventions for defining impingement and entrainment and mortality:

- Impingement: Occurs when any life stage of fish and shellfish are pinned against the outer part of an intake structure or against a screening device during intake water withdrawal. Impingement may also occur when an organism is near a screen but unable to swim away from the intake structure because of the water velocity at the intake.
- Entrainment: Occurs when any life stages of fish and shellfish are drawn into the intake water flow entering and passing through a cooling water intake structure and into a cooling system.
- Impingement Mortality: The death of fish or shellfish due to impingement. It may also include organisms removed from their natural ecosystem and lacking the ability to escape the cooling water intake system and thus subject to mortality. Note that impingement mortality need not occur immediately. Impingement may cause harm to the organism which results in mortality at some time after impingement. For purposes of this rule, EPA has defined impingement mortality as the death of those organisms collected or retained by a sieve with a maximum opening of 0.56 inches; this includes both the 3/8-inch sieve and a 1/2-inch by 1/4-inch mesh.[47]
- Entrainment Mortality: The death of fish or shellfish due to entrainment. This is typically associated with mortality related to small organisms that pass the entire way through a facility and are killed as a result of thermal, physical, or chemical stresses. This term also includes the death of those fish and shellfish that may occur on fine mesh screens or other technologies used to exclude the organisms from entrainment. For purposes of this rule, EPA defined entrainment mortality as the death of those organisms passing through a sieve with a maximum opening of 0.56 inches.

Impingement mortality is typically less than 100 percent of the impinged organisms if a fish return or backwash system is employed. Impingeable organisms are generally not very small fish or early life stages (e.g., those that can pass through 3/8-inch mesh screens), but typically are fish with fully formed scales and skeletal structures and well-developed survival traits such as behavioral responses to avoid danger. EPA's data demonstrate that, under the proper conditions, many impinged organisms can survive.

Entrainable organisms generally consist of eggs and early life stage larvae. Early larvae generally do not have skeletal structures, have not yet developed scales, and in many cases are incapable of swimming for several days after hatching. EPA has found that entrainable organisms that are collected after interaction with the CWIS show poor survival in the case of most eggs, and essentially no survival of larvae. Consequently, on the basis of the record information it has reviewed, EPA concluded for purposes of this rule that all entrained organisms die, i.e., no entrained organisms survive. (See, for example, 76 FR 22188 [April 20, 2011] and 69 FR 41620 [July 9, 2004].) Therefore, without entrainment control, entrainment is assumed to lead to entrainment mortality. Also see Chapter A7 of the Phase II Regional Studies Document (DCN 6–0003; EPA–HQ–OW–2002–0049–1490).

Whether an organism near a cooling water intake structure is impinged or entrained is a function of the screen mesh size. Holding the number and size distribution of organisms at the intake constant, a larger screen mesh size will result in relatively more entrainment, while a smaller mesh size will result in

[46] Typically, cooling water intake structures use various screening devices to prevent objects (e.g., debris, trash) from being drawn in with the cooling water and ultimately clogging or damaging the cooling water system, especially the condenser or heat exchanger components.

[47] Mesh sizes of 3/8″ are commonly referred to as coarse mesh; this refers to the size of the screen opening (in contrast to fine mesh) and not the roughness of the mesh material.

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relatively more impingement. Historically, traveling screens deployed by power plants used a 3/8-inch mesh size. For this reason, most studies and reports referring to impingement are in fact referring to those organisms impinged on a 3/8-inch mesh screen. Similarly, entrainable organisms are those organisms fitting through a mesh of less than or equal to 3/8 of an inch. This also means the majority of entrainable organisms are composed of eggs, larvae, and smaller juveniles. More recent studies, particularly those that evaluate mesh sizes smaller than 3/8 of an inch, continue to refer to impingement as any organism caught on the screen. This can cause some confusion because many organisms that would have been entrained with a 3/8-inch mesh instead become impinged by the finer mesh. These are referred to as impinged entrainables or ''converts.'' EPA has also found that most studies of entrainment are biased toward the larger (older) larvae with higher survival rates and do not analyze survival of smaller larvae. This bias implies a focus on larvae body lengths sufficient to have begun scale and bone development, and it generally reflects the more motile early life stages. EPA found that these study findings cannot be applied to smaller and less motile life stages, which are incapable of avoidance responses. It is also important to note that preventing entrainment by some exclusion technologies might result in very high entrainment reductions by converting entrainment to impingement, but these impinged organisms may have an even lower likelihood of surviving impingement than larger potentially impinged organisms. Therefore, while entrainment refers specifically to passage through the cooling water intake system, entrainment mortality also includes those smaller organisms killed by exclusion from the cooling water intake system. Today's rule uses the 3/8-inch mesh size as part of the definition of impingement mortality and entrainment mortality as a means of clearly differentiating those organisms that might be susceptible to impingement or entrainment, and thereby avoids any confusion over the status of impinged entrainables or ''converts.''

Generally, two basic approaches can be used to reduce impingement mortality and entrainment. The first approach is flow reduction, where the facility installs a technology or operates in a manner to reduce or eliminate the quantity of water being withdrawn. Reduced volumes of cooling water produce a corresponding reduction in impingement and entrainment and, therefore, reduced impingement mortality and entrainment mortality. It should be noted that, at electric generators, flow reduction could be achieved, perhaps most effectively, by installing more energy efficient production, thereby requiring less cooling per unit of electricity generated. The second way to reduce impingement and entrainment is to install technologies or operate in a manner that either (1) gently excludes organisms or (2) collects and returns organisms without harm. Exclusion technologies or practices divert those organisms that would have been subject to impingement and entrainment away from the intake. Collection and return technologies are installed to collect and return organisms to the source water, allowing impingement to occur but possibly preventing impingement mortality.

Although not available to all facilities, two other approaches to reducing impingement and entrainment are (1) relocating the facility's intake to a less biologically rich area in a waterbody, and (2) reducing the intake velocity. Relocating an intake farther from shore or at greater depths can be effective at entrainment reduction but is not available to many inland facilities because the distance or depths required to reach less biologically-productive waters are not generally available. Further, while a far offshore intake may exhibit a lower density of organisms, the species found will change as a function of distance from the shoreline as well as depth in the water column. Therefore, it may not always be desirable to relocate an intake structure. A reduced intake velocity provides motile organisms the opportunity to swim away from the intake structure. This approach can be very effective in reducing impingement but has no effect on entrainment.

Sections 1 and 2 below further describes flow-reduction and exclusion technologies.

1. Flow Reduction

Flow reduction is commonly used to reduce impingement and entrainment. For purposes of this rulemaking, EPA assumes that entrainment and impingement (and associated mortality) at a site are proportional to source water intake volume. Thus, if a facility reduces its intake flow, it similarly reduces the amount of organisms subject to impingement and entrainment.[48] Some common flow reduction technologies are variable frequency drives and variable speed pumps, seasonal operation or seasonal flow reductions, unit retirements, use of alternate cooling water sources, water reuse, and closed-cycle cooling systems. For additional detailed information on these technologies as well as others, see Chapter 6 of the TDD, ''California's Coastal Power Plants: Alternative Cooling System Analysis'' (DCN 10–6964), and EPRI's ''Fish Protection at Cooling Water Intake Structures: A Technical Reference Manual'' (DCN 10–6813).

a. Variable Frequency Drives and Variable Speed Pumps

A facility with variable speed drives or pumps operating at their design maximum can withdraw the same volume of water as a conventional circulating water pump. However, unlike a conventional circulating water pump, variable speed drives and pumps allow a facility to reduce the volume of water being withdrawn for certain periods. The pump speed can be adjusted to reduce water withdrawals when cooling water needs are reduced, such as when ambient water temperatures are colder (and therefore capable of dissipating more heat), when fewer generating units are operating or when fuel is more efficiently burned. In site visits, EPA found that variable drives and pumps were typically used at units operating below capacity, such as load-following units. EPA estimates that facilities with intermittent water withdrawals could achieve a 5 to 10 percent reduction in flow.[49] For this reason, many baseload generating units and continuously operated manufacturing processes will obtain limited reductions in flow from using these technologies. EPA is further aware that some facilities may need to

[48] Impingement rates are related to intake flow, intake velocity, and the swimming ability of the fish subject to impingement. Entrainment is generally considered to be proportional to flow and therefore a reduction in flow results in a proportional reduction in entrainment, as EPA assumes for purposes of national rulemaking that entrainable organisms are uniformly distributed throughout the source water. EPA has consistently applied this assumption throughout the 316(b) rulemaking process (for a discussion of proportional flow requirements in the Phase I and II rules see, e.g., 66 FR 65276 and 69 FR 41599; also see EPA's 1977 draft guidance manual for 316(b), available at DCN 1–5045–PR from the Phase I docket) and continues to assume that it is broadly applicable on a national scale and is an appropriate assumption for a national rulemaking. EPA recognizes that this assumption does not necessarily apply when relocating or varying the time pattern of withdrawals, such that these may be effective strategies to reduce impingement and entrainment in some locations.

[49] Withdrawals of colder water could allow facilities to reduce their intake flow using variable drives and pumps, but EPA does not have data on the efficacy or availability of this approach.

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withdraw water for cooling even while the facility is not in production, such as facilities on standby status, or nuclear facilities where the heat energy generated by fission must still be dissipated while the facility is out of service. As a result, EPA determined that variable frequency drives and variable speed pumps, while useful in specific setting and circumstances, are not BTA candidates because the flow reduction technologies have limited application and availability, and are not a high performing technology as an entrainment control measure.

b. Seasonal Operation or Seasonal Flow Reductions

Seasonal operation or seasonal flow reduction refers to the reduction or elimination of a quantity of water withdrawn either during periods of low demand for electricity output, or to coincide with certain biologically important periods. Most facilities that currently employ seasonal flow reductions do so to limit thermal impacts or to reduce entrainment, because entrainment often has a peak season, particularly during a local spawning season. Freshwater drum, for example, perform broadcast spawning during early summer when water temperatures reach about 65 degrees Fahrenheit.

During specific peak entrainment periods, a facility could scale back its operation (or perhaps not operate at all), thereby reducing or eliminating the volume of cooling water withdrawn. This could be accomplished through a combination of variable speed pumps or shutting down some portion of the pumping system. Seasonal flow reduction could also consist of operating a closed-cycle recirculating system as defined at § 125.92(c)(1) as once-through during part of the year and as a closed-cycle system during the peak entrainment season. (EPA notes that closed-cycle cooling has been rejected as noted in the previous section, and discussed in more detail below.) Facilities could also choose to schedule regular maintenance to occur during these high entrainment periods. These maintenance activities often require the facility to reduce or cease operations and can be timed to coincide with the most biologically productive periods. Through site visits, EPA gathered information on species present at facilities and has identified some sites where entrainment appears to be significant all year long, and other sites where peak entrainment occurs in as few as three to four months of the year.[50] However, if all power-generating facilities in a local area were to stop operating at the same time, there could be difficulty in supplying electricity to the area. Therefore, EPA concluded that seasonal operations have limited nationwide application for controlling entrainment and are thus not widely available entrainment reduction technology.

Impingement is generally more sporadic, less predictable, and more difficult to address with seasonal operation. For example, clupeid species, such as gizzard shad, experience impingement episodes sporadically throughout the winter and spring during periods of especially cold water temperatures, or sporadically throughout the summer and fall during periods of low dissolved oxygen.

c. Unit Retirements

Some power plants units have been retired and others have essentially ceased all operations but have not been formally retired or decommissioned. The reasons for their inactivity vary,[51] but the end result is the facility no longer needs cooling water withdrawals for these units. Similarly, manufacturers may retire processing units as market demand changes, process lines are moved to other sites, or production technologies change. Unit closures provide clear reductions in flow, but the demand for electricity (or other products) might dictate that production be increased at the facility in question or at another facility altogether; there is usually no guarantee that the intake flow will be permanently retired. EPA expects flow reductions due to unit closures could be reasonably included as part of a facility's impingement mortality and entrainment reductions strategy. Given the number of variables involved in the decision to retire a unit and the likelihood of a facility having a unit that is ready to retire at promulgation of the final rule, unit retirements are not a nationally available entrainment reduction measure. See Section VIII for further discussion of how a facility can take credit for flow reductions attributable to unit closures.

[50] See DCN 10–6702 and its attachments for examples of spawning ''seasons.''

[51] Note that some generating units are retired by the owner (*i.e.,* the unit is no longer considered sufficiently profitable to operate) or is rarely dispatched by its independent system operator for market-driven reasons (*i.e.,* the unit cannot deliver at a competitive price except during limited peak seasons; see also § 125.94(c)(12)). They may also be mothballed, placed on cold storage, or maintained in various other states of operational readiness.

d. Use of Alternate Cooling Water Sources

While not reducing the overall usage of water at a facility, using an alternate source of cooling water can reduce impingement and entrainment if the alternate source substitutes for withdrawals from surface waters. An example is using ''gray'' water as a source of cooling water, such as a facility that reaches an agreement with a nearby wastewater treatment plant to accept the wastewater treatment plant's effluent as a source of cooling water.[52] Such alternate sources are limited by available capacity and consistency of flow. Increasing competition for these sources of water may make this a more challenging approach for existing facilities than for new facilities that are not yet fixed in location. In principle, alternate sources could be used to fulfill either a fraction or all of a facility's cooling water demands. In practice, the location of alternate sources, the costs of moving water from the alternate source to the facility, and whether the facility uses a once-through or closed-cycle recirculating system as defined at § 125.92(c) will determine whether the alternate source can meet all or a portion of the facility's cooling water needs. All these factors limit the widespread availability of alternate cooling water sources as an entrainment reduction measure, however use of alternative sources of cooling water such as wastewater treatment effluent could be attractive for certain facilities where the cost of retrofitting or other site-specific circumstances are favorable.[53]

e. Water Reuse

Typically associated with manufacturing facilities, water reuse (defined as using water for multiple processes) can reduce the volume of water needed for cooling, process, or other uses. For example, a facility might withdraw water for non-contact cooling water and then reuse the heated effluent as part of an industrial process. In effect, the facility has eliminated the need to withdraw additional water for the latter

[52] See, for example, EPA's site visit report for PSEG's Linden Generating Station (DCN 10–6557), which has a capacity of 1230 MW, 35 percent CUR, and uses 7–8 mgd of gray water as the sole source of makeup water for its cooling towers.

[53] For maps showing which electric generators are near a source of available reuse water for cooling, see Tidwell, V., J. Macknick, K. Zemlick, J. Sanchez, and T. Woldeyesus. 2013. ''Transitioning to Zero Freshwater Withdrawal for Thermoelectric Generation in the United States.'' (submitted). See also the accompanying presentation given at the American Geophysical Union Fall 2012 Meeting available at *http://www.nrel.gov/docs/fy13osti/57444.pdf.*

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process. EPA has observed significant water reuse at manufacturing facilities but has not developed national level data for such reuse because of the range of different manufacturing sectors and the significant variability in manufacturing processes appropriate for reuse. For example, during site visits, EPA observed that it may be difficult to quantify specific water reuse at complex facilities. (See, for example, the site visit report for ArcelorMittal, a steel mill at DCN 10–6551.) For additional detail on water usage in specific industrial sectors, see Chapters 4 and 8 of the TDD.

Increasingly, electric utilities are adopting water reuse to meet a portion or all of their cooling water demands. Water reuse can enhance the reliability of power generation in water-limited environments. Given the complex use (and reuse) patterns for some facilities and the lack of reuse at other facilities, water reuse cannot be considered as a widely available entrainment reduction option.

f. Closed-Cycle Cooling Systems

Closed-cycle cooling systems allow a facility to transfer its waste heat to the environment using significantly smaller quantities of water relative to once-through cooling, and in some cases no water. The main types of closed-cycle cooling systems are wet cooling, dry cooling, hybrid cooling, and impoundments. Each is described below.

i. Wet Cooling Systems

In a wet cooling system, cooling water that has absorbed waste heat transfers that heat through evaporation of some of the heated water into the surrounding air and recirculates the now cooled water to continue the cooling process.[54] This process enables a facility to reuse the remaining water, thereby reducing the quantity of water that must be withdrawn from a waterbody. Because the heat is transferred through evaporation, the amount of water withdrawn from the water source is greatly reduced, though not eliminated completely, because make-up water is required to replace that lost through evaporation and blowdown.[55] The two main types of wet cooling systems are natural draft and mechanical. While wet cooling systems reduce withdrawals significantly relative to once-through systems, they can increase the consumptive use of water because they rely on evaporation (which is not returned to the waterbody) for heat dissipation. When once-through cooling is used and withdrawals are a significant portion of the source waterbody, the return of heated water might contribute to greater evaporation from the waterbody relative to the waterbody's normal evaporation rate. EPA does not have conclusive data on the relative magnitude of these effects, but the data do suggest that the relative difference in evaporation is not so great that it will play a major role in determining a cooling system type in most watersheds. EPA examined available information on evaporation losses in DCN 12–6673, including a comparison to evaporative losses from the downstream effluent plume of once-through cooling systems. While EPA recognizes that evaporative losses from closed-cycle systems are greater, EPA's analysis does not suggest that the difference is substantial enough to outweigh the significant reduction in adverse environmental impacts to aquatic organisms. However, the relative loss of water through evaporation for closed-cycle and once-through systems is site-specific, depending on the exact design of the systems.

There are two common designs for wet cooling systems. A natural draft cooling tower can be as tall as 500 feet and has a hyperbolic shape. The height of these towers creates a temperature differential between the top and bottom of the tower, which creates a natural chimney effect that transfers heat as heated water contacts rising air. In contrast, mechanical cooling towers rely on motorized fans to draw air through the tower and into contact with the heated water.[56] These towers are much shorter than natural draft cooling towers (typically 30 to 75 feet tall) and can be built in groups. Mechanical cooling towers may require more land area than natural draft cooling towers for an equivalent amount of cooling. Both types of towers require electricity for pumps, but mechanical draft towers also require electricity to operate the fans. In both cases, the electricity need of the towers reduces an electric generating facility's net generating output. Thus, the monetary and environmental costs of this reduction in energy efficiency must be considered. These environmental costs include human health and welfare effects from increased air emissions (from burning additional fuel to make up for the power that cannot be sold) and the global climate change effects of increased greenhouse gas output at fossil-fueled facilities (these costs are now explicitly considered in the benefit-cost analysis; see Section X below). Both natural draft and mechanical cooling towers can operate in freshwater or saltwater environments. Saltwater applications typically require more make-up water than freshwater applications, making them less efficient in reducing water withdrawals. Optimized cooling towers can achieve flow reductions of 97.5 and 94.9 percent or better for freshwater and saltwater sources, respectively.

ii. Dry Cooling Systems

Dry cooling systems virtually eliminate the need for cooling water withdrawals.[57] Unlike wet cooling systems, waste heat in dry cooling systems is transferred completely through convection and radiation, rather than evaporation. Direct dry cooling is much like a car radiator; turbine exhaust steam passes through tubes or fins for cooling, and the condensate is returned to the boiler to be reheated into steam to propel the turbine. The system is completely closed to the atmosphere, and there is no contact between the outside air and the steam or the resulting condensate. Because of the heavy reliance of dry cooling on ambient air temperatures and the lower efficiency of heat transfer through convection and radiation, dry cooling systems are much larger and therefore more expensive[58] than wet cooling systems for a given cooling load. While dry cooling systems are not uncommon in the U.S. (see DCN 10–6943), they have typically been built at smaller generating units or in areas where limited water supplies might make

[54] In addition, a smaller portion of the heat is also removed through direct contact between the warm water and the cooler surroundings; this is known as sensible heat.

[55] Cooling towers must replace water lost to evaporation; this is referred to as makeup water. Additionally, as water evaporates, dissolved solids and other materials gradually increase in concentration in the circulating water and can cause operational difficulties. To minimize these issues, cooling tower operators continually discharge a small portion of the circulating flow and replace it with makeup water; this is referred to as blowdown.

[56] Modular cooling tower units provide an additional cooling tower alternative. Modular cooling towers resemble mechanical cooling towers, but are portable, typically rented for short-term periods and quickly assembled.

[57] Dry cooling systems blow down some of the circulating water in the cooling system to prevent the buildup of materials in the condenser. However, the volume of makeup water is extremely low—a dry cooling system typically reduces intake flows by 98–99 percent over a comparable once-through cooling system.

[58] The construction and capital costs for dry cooling towers have been reported as four to 10 times more expensive as wet cooling towers, and the auxiliary power consumption for dry cooling is higher than for wet cooling. See DCN 10–6679. EPA recognizes that costs for dry cooling may have decreased since this document was written, but costs for dry cooling are still markedly higher than those for wet cooling. The other challenges associated with dry cooling remain unchanged.

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uncertain the availability of either once-through cooling or wet cooling make-up water, such as the arid southwestern United States. Dry cooling has not been used for circulating water cooling at nuclear facilities.

iii. Hybrid Cooling Systems

In certain applications, a facility could choose a hybrid cooling system design that incorporates elements of both wet and dry cooling. Typically, the base of the tower functions as a wet cooling system and the upper portion as a dry cooling system. The most common reason for this design is to reduce the visible plume of water vapor, which is accomplished by recapturing some of the water vapor evaporated in the wet portion of the tower. This design is also usually much shorter than natural draft wet towers and can also include plume abatement controls. Another version of the hybrid cooling system also includes both wet and dry cooling sections, but the dry section functions to directly cool a portion of the turbine exhaust steam. The benefits of such a tower may include substantial water savings as well as reduction in power plant efficiency losses associated with just dry cooling.

iv. Impoundments

Impoundments are surface waterbodies that serve as both a source of cooling water and a heat sink. As with cooling towers, impoundments rely on evaporative cooling to dissipate the waste heat; a facility withdraws water from one part of the impoundment and then discharges the heated effluent back to the impoundment, usually in another location to allow the heated water time to cool. Depending on local hydrology, impoundments may also require makeup water from another waterbody. Impoundments can be man-made or natural, and can be offset from other water bodies or as part of a ''run of the river'' system (the latter are sometimes referred to as cooling lakes).

2. Exclusion and Collection Technologies

Over the last several decades, numerous technologies in addition to specific flow reduction measures such as velocity controls and closed-cycle cooling have been developed in an effort to minimize impingement mortality and entrainment associated with cooling water intake systems. The following section summarizes the most widely used technologies and the most effective and best-performing technologies, such as screens, barrier nets, aquatic filter barriers, and collection and return systems. For additional detailed information on these technologies and others, also see Chapter 6 of the TDD, ''California's Coastal Power Plants'' report (DCN 10–6964) or EPRI's ''Fish Protection at Cooling Water Intake Structures'' report (DCN 10–6813).

a. Screens

There are several types of screens that offer protection that are discussed below, including traveling screens and cylindrical wedgewire screens. Not described in this section are fixed screens that are used simply for the purpose of debris exclusion but do not offer protection to fish, larvae, and eggs.

i. Traveling Screens

Traveling screens are a technology in place as part of most cooling water intake structures. These screens originally were designed to prevent debris from entering the cooling water system, but they also prevent some fish and shellfish from entering the cooling water system. Traveling screens have been installed in a wide variety of operating and environmental conditions: salt water, brackish water, freshwater, and icy water, as well as river, lake and tidal applications. On the basis of the technical survey, EPA found 93 percent of electric generators and 73 percent of manufacturers employ traveling water screens or other intake screens. Many types of traveling water screens (e.g., through flow, dual flow, center flow) are used. The most common design in the United States is the through flow system. The screens are installed behind bar racks (trash racks) but in front of the water circulation pumps. The screens rotate up and, while out of the water, debris and impinged organisms are removed from the screen surface by a high-pressure spray wash. Screen wash cycles are triggered either manually or by a certain level of head loss across the screen (indicating clogging). By definition, this technology works by collecting (i.e., impinging) fish and shellfish on the screen. Ideally, traveling screens would be used with a fish handling and return system, as discussed below. The return system should be regularly maintained to prevent biofouling or other blockages that may affect survival.

ii. Cylindrical Wedgewire Screens

Unlike traveling screens, cylindrical wedgewire screens are a passive intake system. Wedgewire screens, also called ''V'' screens or profile screens, consist of triangular-shaped wires arrayed on a cylindrical framing system, with long slots between the wires, lengthwise along the screen. Slot sizes for conventional traveling screens typically refer to a square opening (⅜ inch by ⅜ inch) that is punched, molded, or woven into the screen face. Wedgewire screens are constructed differently, however, with the slot size referring to the distance between longitudinally adjacent wires. These screens are designed to have a low through-slot velocity (less than 0.5 fps or 0.15 meter per second) and typically have smaller slot sizes than a coarse mesh traveling screen. The entire wedgewire structure is submerged in the source waterbody. (See Chapter 6 of the TDD for an illustration of these screens.)

When necessary conditions regarding placement in the waterbody are met, these screens exploit physical and hydraulic exclusion mechanisms to achieve consistently high impingement reductions, and as a result, impingement mortality reductions. Wedgewire screens require an ambient crossflow current to maximize the sweeping velocity provided by the waterbody. The screen orientation allows the crossflow to carry organisms away from the screen allowing them to avoid or escape the intake. Lower intake velocities also allow fish to escape from the screen face. Entrainment reductions can also be observed when the screen slot size is small enough and intake velocity is low enough to exclude egg and larval life stages.[59] Limited evidence also suggests that extremely low intake velocities can allow some egg and larval life stages to avoid the intake because of hydrodynamic influences of the crossflow. Therefore, performance is dictated largely by local conditions that are further dependent on the source waterbody's biological composition. Costs of wedgewire screens increase significantly as slot size and design intake velocity decrease because the cumulative size of the screen (or number of screens) must grow in order to accommodate the same flow of cooling water. Wedgewire screens can also employ cleaning and deicing systems such as air-burst sparging to help maintain open intake structures and low intake velocities.

According to data from the industry questionnaire, EPA's site visits, and industry documents, dozens of facilities across the United States employ cylindrical wedgewire screens. However, wedgewire screens are not feasible for all facilities, particularly where intakes are in shallow water or have limited shoreline frontage. Also,

[59] Note that this is entrainment exclusion and not necessarily related to the survival of entrainable organisms.

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wedgewire screens might not be feasible where the size and number of wedgewire screens would interfere with navigation of vessels. As described above, locations also need to have an adequate source water sweeping velocity. Most of the performance data for wedgewire screens is based on coarse mesh slot sizes with an intake velocity of 0.5 fps. Because it is extremely difficult to measure impingement and entrainment reductions in the field, most performance data for wedgewire screens is based on barge and lab studies.[60] EPA does not have data on the performance of fine mesh wedgewire screens on entrainment survival. Consequently, EPA has considered wedgewire screens only for impingement mortality. For additional discussion of the specific design and operation of cylindrical wedgewire screens, see Chapter 6 of the TDD. The following section discusses the importance of mesh size to impingement mortality and entrainment reductions.

iii. Screen Mesh Size Considerations

Coarse Mesh

Coarse mesh traveling screens are the typical traveling screen fitted on the majority of cooling water intakes. A large number of facilities have intake screens with ⅜-inch (9.5 mm) mesh panels.[61] This size mesh is common because, as a general rule, the maximum screen slot size is never larger than one-half of the condenser tube diameter (the condenser tubing is the narrowest point in the cooling water system and, as such, is most susceptible to clogging from debris), and this tubing is typically ¾ or ⅞ inch in diameter. Mesh of ⅜-inch (roughly 9.5 mm) size does not prevent entrainment and without any other precautions can lead to high mortality of impinged fish. Coarse mesh traveling screens have been in use by both power plants and manufacturers for more than 75 years and represent the baseline technology. Similarly, the majority of successful wedgewire installations are coarse mesh.

Fine Mesh

Fine mesh traveling and wedgewire screens are similar to coarse mesh screens. The only difference is the size of the screen mesh. Fine mesh traveling screens have been in use since the 1980s. Typically, facilities have incorporated fine mesh in an effort to reduce entrainment. The mesh size varies, depending on the organisms to be protected, but typically range from 0.5 to 5 mm. Data in the record demonstrate that entrainment typically decreases as mesh size decreases. Slot sizes larger than 2 mm do not prevent eggs from passing through the screen. Converting traveling screens from coarse mesh to fine mesh often requires adding more screens in order to maintain the same flow, since the open area of a fine mesh screen is less than the open area of a coarse mesh screen. Adding more screens is one way to maintain that flow.[62] EPA estimates that as many as 17 percent of existing intakes could not be enlarged to accommodate a 2 mm mesh, and as many as 55 percent of existing intakes could not accommodate a 0.5 mm slot size under conditions of low-intake velocities. For these reasons, fine mesh screens are available for some locations, but they are not the best performing technology and are not an available technology for the industry as a whole for IM&E. For more details, see Chapter 6 of the TDD.

b. Barrier Nets

Barrier nets are nets that fully encircle the intake area of water withdrawal, from the bottom of the water column to the surface, and prevent fish and shellfish from coming in contact with the intake structure and screens. According to data from the industry questionnaire (as of the year 2000), at least a half dozen facilities employ a barrier net. Typically, barrier nets have large mesh sizes (e.g., ½-inch or 12.7 mm)[63] and are designed to prevent impingement. Because of the large mesh size, they offer no reduction in entrainment. They are often deployed seasonally, wherever seasonal migrations create high impingement events or to avoid harsh winter conditions that jeopardize integrity of the net. Barrier nets also prevent impingement of shellfish on the intake traveling screen. Shellfish such as crustaceans can pose a unique issue for traveling screens; shellfish are not impinged, but they can attach to the traveling screen surface and are not removed from the traveling screen by pressure wash sprays. Barrier nets have been shown to be helpful in this regard.

c. Aquatic Filter Barriers

Aquatic Filter Barriers (AFBs) consist of water-permeable fabric panels with small pores (less than 20 microns). They are similar to barrier nets in that they extend throughout the area of water withdrawal from the bottom of the water column to the surface. AFBs reduce both impingement mortality and entrainment because they present a physical barrier to all life stages. The surface area of an AFB is quite large compared to a traveling screen, allowing for extremely low water velocities. The low velocity allows non-motile organisms to drift away. EPA is aware of one power plant that used an AFB but notes that this facility recently ceased operations.[64] EPA has updated performance data for AFB for small flow intakes, but it does not have enough data to evaluate the technology at large intakes or in all water bodies. EPA does not consider this technology to be demonstrated and available as a nationwide BTA candidate.

d. Collection and Return Systems

Conventional traveling screens were not designed initially with the intention of protecting fish and aquatic organisms that become impinged against them. The organisms were often handled in the same manner as debris on the screens. Marine life can become impinged against the screens because of high intake velocities that prevent their escape. Prolonged contact with the screens can suffocate organisms that are unable to escape or result in descaling injury and latent mortality. Organisms that survive initial impingement and removal are not always provided with a specifically designed mechanism to return them to the waterbody and are often handled in the same way as other screening debris. Other objects, such as leaves and trash, that are collected on the screen are typically removed with a high-pressure spray and deposited in a dumpster or debris return trough for disposal. Exposure to high pressure sprays and other screening debris can cause significant injuries that result in latent mortality or increase the susceptibility to predation or re-impingement. Screens are rotated periodically on a set time interval or when the pressure differential between the upstream and downstream faces exceeds a set value.

Conventional traveling screen systems have been modified to reduce impingement-related mortalities with

[60] EPA expects that properly designed wedgewire screens have a design intake velocity of 0.5 fps, therefore intakes with wedgewire screens will meet the impingement standard at § 125.94(c)(2) and there is no need to separately pre-approve this technology as in the remanded 2004 Phase II rule.

[61] In today's rule the EPA recognizes that ½- by ¼-inch mesh is used in some instances and perform comparably to the ⅜-inch square mesh.

[62] A facility could also increase its intake velocity.

[63] Barrier net mesh sizes vary, depending on the configuration, level of debris loading, species to be protected, and other factors.

[64] This facility ceased operations for reasons unrelated to any requirements or measures addressing cooling water intake impingement or entrainment.

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collection and return systems. In its simplest form, these systems are composed of a return flume or trough with sufficient water volume and flow to enable impinged organisms to return to the source water. Return systems should be designed to avoid predation and latent mortality while organisms are in the flume, maintain an appropriate water depth in the flume for high survival of the organisms, located at an appropriate elevation to avoid large drops of the organisms back to the surface water (or large hydraulic jumps if the end of the return is below the water's surface), and sited to avoid repeated impingement of the organisms by the intake structure.

Some facilities have modified conventional coarse mesh traveling screen systems to reduce impingement mortality. They did this by removing fish trapped against the screen and returning them to the receiving water with as few injuries as possible. The first modified screens, also known as Ristroph screens, feature capture and release modifications. In the simplest sense, these screens are fitted with troughs (also referred to as buckets) containing water that catch the organisms as the screen rises out of the water and the organisms are sprayed off of the screen. The return component consists of a mechanism to remove impinged fish gently from the collection buckets, such as a low-pressure spray. The buckets empty into a collection trough that returns fish to a suitable area in the source waterbody. These modified screens have shown significant reductions in impingement mortality compared with unmodified screen systems.

Data from early applications of the Ristroph screen design showed that while initial survival rates might be high at some installations, latent mortality rates were higher than anticipated. This indicated that organisms could sustain significant injuries during the impingement and return process that were not immediately fatal. According to a study conducted by Ian Fletcher in the 1990s (see DCN 5–4387), industry identified several additional critical screen modifications to address latent mortality. These included redesigning the collection buckets to minimize turbulence, adding a fish guard rail/barrier to prevent fish from escaping the collection bucket, replacing screen panel materials with ''fish-friendly,'' smooth woven mesh, and using a low-pressure wash to remove fish before any high-pressure spray to remove debris. The Fletcher analysis also identified longer impingement duration, insufficient water retention in the buckets, and exposure to the air and temperature extremes as conditions that could negatively affect fish survival. Finally, these findings indicate that modified Ristroph screens must be rotated continually instead of the periodic rotation schedule common with conventional screen systems. Performance data for modified traveling screens with fish-friendly fish return systems, sometimes referred to as post-Fletcher modifications, show low levels of impingement mortality across a wide variety of waterbody types and fish species. Additionally, recently developed screen designs (such as the Passavant Geiger, Beaudrey WIP, and Hydrolox screens) have also shown promise in reducing impingement mortality.

For additional and more detailed discussion of the specific design and operation of these screen modifications, see Chapter 6 of the TDD.

3. Other Technological Approaches

a. Intake Location and Velocity Caps

The most common intake location for a cooling water intake structure is along a shoreline. In some water bodies, however, shoreline locations are thought to have a potential for greater environmental impact because the water is withdrawn from the most biologically productive waters, especially those containing a high density of organisms in earlier life stages, such as nursery areas. Some facilities employ an offshore intake to withdraw water from less biologically productive areas to reduce impingement and entrainment relative to intakes in more productive shoreline areas. Reduction in impingement mortality and entrainment due to intake location is highly site-specific. The greatest potential for reductions is found with far offshore locations at distances of several hundred feet, not found on many rivers and streams. Both depth and the offshore location must be evaluated to determine whether fish densities and species distribution there are substantially different than those near the shoreline. Two areas where far offshore locations are commonly used today are the oceans and Great Lakes.

EPA found that several offshore intakes are fitted with a velocity cap.[65] Velocity caps are a physical structure rising vertically from the sea bottom and are placed over the top of an intake pipe. Intake water is withdrawn through openings in the velocity cap so that it converts the direction of water flow into the pipe from vertical to horizontal. The velocity cap does not act to reduce the velocity,[66] but the horizontal flow provides a physiological trigger in fish, which induces an avoidance response to reduce impingement mortality. The velocity cap further serves to limit the zone of influence of the intake to the depth level at which the velocity cap is situated, thus affecting only the life stages that live at that depth. Velocity caps are also usually equipped with supports and bar spacing selected to prevent larger aquatic organisms (e.g., sea turtles or marine mammals) from entering the intake pipe. Because velocity caps operate under the principle that the organisms can escape the current, they do not offer entrainment reductions over and above those achieved by being located offshore. Reductions in entrainment observed with velocity caps occur because of the difference in organism densities in far offshore deep water compared to a surface intake at the shoreline.

Far offshore velocity caps have limited application in oceans and the Great Lakes, are not available in other water bodies, and are therefore not available as a candidate for a national BTA. However, the technology is a demonstrated high performing technology, and is therefore included as a compliance alternative for those facilities where the technology is available. For additional and more detailed discussion of the specific design and operation of offshore intake locations and velocity caps, see Chapter 6 of the TDD.

b. Reduced Intake Velocity

Impingement mortality can be reduced greatly by reducing the through-screen velocity in any screen.[67] Reducing the rate of flow of cooling water through the screen (through-screen velocity) to 0.5 fps or less reduces impingement of most fish because it allows them to escape the intake current. (See 66 FR 65274 [December 18, 2001] and DCN 2–028A, EPRI's ''Technical Evaluation of the Utility of Intake Approach Velocity as an Indicator of Potential Adverse

[65] Others can be fitted with a cylindrical wedgewire screen, or might simply be an open pipe.

[66] EPA's data show that velocity caps operate at velocities above and below the 0.5 fps and can be effective using either design.

[67] Limited lab studies indicate that entrainment also can decrease as through-screen velocity decreases and that through-screen velocity can have an effect on entrainment survival rates, although such data is extremely variable by species (see DCN 10–6802 and DCN 10–6803). In any case, EPA does not consider a reduced intake velocity as an effective technology for reducing entrainment, because entrainable organisms generally lack motility.

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Environmental Impact Under Clean Water Act 316(b).'') As a result, some facilities have designed and operate their modified traveling screens or wedgewire screens so as not to exceed a through-screen velocity of 0.5 fps. Swim speed studies demonstrate that for most facilities, an intake velocity of 0.5 fps or less will result in 96 percent or better reductions in impingement mortality for most species. EPA notes that preliminary results from recent studies of fine mesh screens suggest that at even lower intake velocities such as 0.25 fps, some hydrodynamic influences may reduce entrainment mortality even more, because flow dynamics are nonlinear. It is unclear as to whether such observations hold true when cooling water withdrawals (water volumes) are large. While higher intake velocities are sufficiently protective for some species of fish, the higher intake velocities are not necessarily protective of all life-stages. For example, younger fish may not be strong swimmers or may have not a developed avoidance response. Therefore higher intake velocities are not a high performing technology. As noted previously, low intake velocity has limited application, and is therefore not available as a candidate BTA technology. However, the technology is a demonstrated high performing technology, and is therefore included as a compliance alternative for those facilities where the technology is available.

D. Technology Basis for Today's Final Rule

As described above, EPA examined the full range of technologies that reduce impingement or entrainment or both. From an assessment of all factors, EPA identified one technology that is best technology available for minimizing the adverse impacts of impingement mortality at existing facilities: modified traveling screens with a fish-friendly fish return. EPA identified no single best technology that is available for minimizing entrainment at existing facilities for today's final rule. For new units at existing facilities, EPA identified mechanical draft wet cooling systems as BTA for both impingement and entrainment.[68]

EPA did not identify any single technology or group of technology controls as the basis for establishing the national BTA standard for entrainment for existing units. Instead, EPA has established a national BTA standard for entrainment for existing units that requires determination of BTA entrainment requirements on a site-specific basis in a structured permitting setting. The framework for determining entrainment requirements provides for the consideration at a minimum of certain specified factors that must be considered in the Director's determination of the BTA controls.

1. Alternative Impingement Mortality Standards for Existing Units

After considering all factors identified above, EPA has concluded that modified traveling screens, such as modified Ristroph screens and equivalent modified traveling screens with fish-friendly fish returns, are a best technology available for minimizing impingement mortality.[69] These screens use ⅜ inch, or similar, mesh with collection buckets designed to minimize turbulence, a fish guard rail/barrier to prevent fish from escaping the collection bucket; ''fish-friendly,'' smooth, woven or synthetic mesh; and a low-pressure wash to remove fish before any high-pressure spray to remove debris. The fish removal spray must be of lower pressure, and the fish return must be fish friendly, provide sufficient water and minimize turbulence. Modified traveling screens generally must be rotated continually to minimize aquatic exposure to impingement or to the air and thus obtain the highest reductions in impingement mortality.

Under the seventh option for complying with the BTA impingement mortality standard in today's final rule, a facility may rely on any technology it chooses so long as it demonstrates through biological compliance monitoring that it achieves the required 12 month impingement mortality performance standard [70] that EPA calculated based on the performance of the BTA technology—modified traveling screens with fish return. As discussed in the TDD (see, for example, TDD Exhibits 11–1 and 11–3), EPA based the 12 month percent mortality performance at § 125.94(c)(7) on data from facilities with traveling screens modified with features to improve the post-impingement survival of organisms such as smooth mesh, continuous or near-continuous rotation of the screens, buckets with guard rails, low pressure sprays for collecting fish, and fish return systems. The statistical basis for the 12 month impingement mortality performance standard includes 26 sets of 12 month survival percentages across 17 facilities demonstrating average impingement mortality rates ranging from 1.6 to 48.8 percent under conditions of 18 to 96 hour holding times. EPA established the 12 month percent mortality as 24 percent which is the arithmetic average of the impingement mortality rates from the 17 facilities. (This is consistent with EPA's proposed rule use of expected value of the beta distribution which can be calculated as the arithmetic average.) **Note:** The 12 month impingement mortality performance standard means that no more than 24 percent of the impinged fish may die or alternatively at least 76 percent of the impinged fish must survive. EPA has occasionally used average annual limitations in the effluent guidelines program, most recently for the pulp and paper industry category (40 CFR 430, promulgated in 1998). In these instances, such as the technology-based BAT, EPA has defined the annual average limitations to be the average level demonstrated by the technology. Thus, EPA's approach to calculating the 12 month percent survival performance standard is consistent with past practice.

EPA recognizes that variability in the technology performance occurs due to changes in seasons, differing intake locations, higher mortality of certain species, and speciation found in different water bodies. By using a full 12 months of data, EPA has ensured that the resulting performance standard reflects the widest range of potential conditions present in EPA's database. EPA has further incorporated variability into the 12 month impingement mortality performance standard by basing it on data from 17 facilities which collectively performed more than 1,500 sampling events beginning as early as 1977. EPA notes that seven facilities had mortality rates less than 10 percent which provides evidence that facilities can, and have, maintained and operated their systems in a manner consistent with the performance standard. Another four facilities demonstrated impingement mortality rates significantly greater than the performance standard of 24 percent, however, EPA notes these facilities were

[68] Although EPA also identified velocity reduction to 0.5 feet per second or less as a candidate best performing technology for impingement mortality, EPA did not promulgate requirements to reduce intake velocity as BTA because it is not available at all facilities; however, the final rule does allow facilities to comply with intake velocity of 0.5 feet per second or less where available.

[69] EPA also considered recent screen designs (such as the Passavant Geiger, Beaudrey WIP, and Hydrolox screens) in evaluating impingement mortality data. In fact, the data set used to calculate the impingement mortality performance standard at § 125.94(c)(7) included a study of performance at a facility employing a Passavant Geiger screen, as well as a facility employing a Beaudrey WIP screen.

[70] In the record, EPA may also refer to this as the 12-month percent survival performance standard, % SPS, or the IM performance standard.

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not required to optimize their technology performance as part of their study, and data collection was not required to achieve a certain level of performance.[71] In each study, EPA has identified elements of the technology operation that a facility could modify to achieve the 12 month percent impingement mortality performance standard. By using the 12 month percent impingement mortality performance standard, EPA has ensured that the resulting performance standard reflects the widest range of potential conditions present in EPA's database. In addition to those studies meeting the criteria for use in the 12 month percent survival performance standard calculations, there are further studies in EPA's record that provide additional performance data showing facilities can, and have, maintained and operated their systems in a manner consistent with the performance standard. EPA's record includes approximately 250 total studies related to impingement (see TDD Exhibit 11A–1).

Despite the overwhelming evidence that the 12 month percent survival performance standard of 24 percent was consistent with demonstrated performance for the best technology, EPA considered other alternatives that might incorporate more variability into a performance standard. EPA concluded that none of the alternatives were consistent with the need for facilities to demonstrate ongoing maintenance and operations over a long period of time, such as a year. Any alternative would be less stringent and would allow facilities to target long-term performance at a level that would be less than the optimal performance demonstrated by facilities with the technology in place. Further, the 12-month average impingement mortality performance standard will require a facility to actively evaluate performance during the 12 month period enabling the facility to optimize the technology to improve performance to counterbalance a result above the standard by one below the standard. If EPA had included a monthly average standard, it would have similarly needed to incorporate allowances for exceedances. Allowing for exceedances would have provided no incentive for improving operations for such exceedances. Therefore, EPA determined that the 12 month impingement mortality performance standard is sufficient to ensure performance consistent with best technology available. For this reason, EPA is not promulgating the monthly average that was included in the proposal. EPA's decision also is consistent with effluent guidelines where compliance with the monthly average limitation is not required for facilities subject to a longer term limitations such as an annual average limitation (e.g., pulp and paper 40 CFR 430 Subpart B AOX limitation).

EPA did not include in the final rule a number of requirements it had considered at proposal. The proposed rule would have required the seasonal deployment of barrier nets on estuaries and oceans as one element of the best technology available for minimizing the impingement mortality of shellfish. EPA has opted not to include any specific requirements for shellfish in the final rule, because EPA's review of the impingement data it used to develop today's final rule impingement performance standard includes data that incorporate shellfish survival as part of the performance standard. Further, as previously explained, the final rule provides for the Director to establish additional requirements where necessary.

EPA expects facilities complying with § 125.94(c) of today's rule by compliance option (7) to track their compliance with the 12 month percent impingement mortality performance standard on an ongoing basis and to proactively modify their technology or operations when a trend in the sampling suggests that they might be in danger of exceeding the 12 month percent impingement mortality performance standard in the future. The 12 month percent impingement mortality performance standard requires that impingement mortality not exceed 24 percent, calculated as the sum total number of fish that were impinged and died within the holding time divided by the sum total number of fish impinged for a 12-month period. EPA expects the ratio will be calculated based either on direct sampling counts, or based on both counts being extrapolated to represent annual counts. Because comments provided data that expanding the proposed 24 to 48 hour holding time requirement would generally not affect the observation of mortality due to impingement, the regulation allows for holding times from 18 to 96 hours.

As explained in more detail in Section VI.E and G below, the BTA technology for impingement does not minimize adverse environmental impacts associated with entrainment.

2. Entrainment Standards for Existing Units

As discussed below, EPA is not basing BTA for entrainment at existing units (that is, excluding new units at existing facilities) on closed-cycle recirculating cooling systems, a highly effective technology, because this technology is not available nationally and therefore does not represent BTA. EPA also has not identified any other effective, available and demonstrated candidate technology (or combinations of technologies) for entrainment reduction at existing units that is available nationally. For other entrainment technologies that might be available on a site-specific basis, see Section VI.E.2 below and Chapter 6 of the TDD. EPA did not select the other flow-reduction technologies (such as variable-speed drives and seasonal flow reductions) as the technology basis for entrainment control measures because these technologies are not uniformly best and are not broadly available for most facilities. Further, EPA has not identified a basis for subcategorizing existing units at which flow reduction technologies are feasible. The effectiveness, availability, and utility to a given facility of flow reduction or other entrainment reduction methods depends on site-specific geographical and biological conditions as well as operations of the facility. For example, this is the reason that EPA did not select relocation of a shoreline intake to far offshore as a technology basis for the BTA entrainment standard because this technology is not widely available for most facilities.

3. Impingement and Entrainment Standards for New Units at Existing Facilities

In contrast to existing units, installing a closed-cycle cooling system at a new unit is far less complex. The technology is also highly effective, generally achieving greater than 95 percent reductions in IM and E (mechanical draft (wet) cooling towers achieve flow reductions of 97.5 percent for freshwater and 94.9 percent for saltwater sources, or by operating the towers at a minimum of 3.0 and 1.5 cycles-of-concentration, respectively). These reductions in flow and the concurrent reductions in impingement and entrainment impacts are among the highest reductions in adverse

[71] For example, the Indian Point study states ''Because of the preliminary nature of this study, the effectiveness of the continuously operating fine mesh traveling screen has not been fully evaluated. Further studies incorporating controls for survival testing, regulation of spray wash pressures, collection efficiency tests, sampling during peak impingement periods for all important species, and better holding facilities, will provide more conclusive results.''

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environmental impact possible at an intake structure.[72]

As described below, EPA has concluded that new units, in contrast to existing units, have much greater flexibility in terms of cooling system design, construction scheduling, and other factors that help minimize many of the negative aspects associated with closed-cycle cooling. For a more detailed discussion of this rationale, see below.

Under the final rule, a new unit at an existing facility, where the facility that withdraws or will withdraw more than 2 mgd when the new unit begins operating will have requirements similar to the requirements of a new facility in Phase I. Under the rule, a new unit (as defined at § 125.92(u) and described above) is required to have a flow limited to that which is commensurate with a closed-cycle recirculating system as it would be applied to the new unit. Today's final rule also includes an alternative approach (similar to Track II in Phase I), in which a facility could comply with the new unit standards by demonstrating that the technologies and operational measures employed will reduce the level of adverse environmental impact from any cooling water intake structure used to supply cooling water to the new unit to a comparable level to that achievable by implementing a closed-cycle recirculating system as defined at § 125.92(c)(1).

As discussed above, today's final rule defines a ''new unit'' at an existing facility as a stand-alone unit the construction of which commences after the effective date of today's final rule. New unit includes stand-alone units that are added to a facility for purposes of the same general industrial operation as the existing facility. This is in contrast to the definition of new facility, where a new facility does not include new units that are added to a facility for purposes of the same general industrial activity (40 CFR 125.83). The provision ''for purposes of the same general industrial operation'' is explicitly included in today's final rule definition of new unit at an existing facility for clarity. A new unit may have its own dedicated cooling water intake structure, or the new unit may use an existing or modified cooling water intake structure. Any unit at an existing facility that does not meet the new unit definition in today's rule is subject to the existing unit provisions.

EPA is adopting more stringent requirements for new units at existing facilities because such new units can be designed and constructed without many of the additional expenses and operational disadvantages associated with retrofitting an existing unit to closed-cycle cooling. For example, the incremental downtime that can be associated with retrofitting to closed-cycle cooling is avoided altogether at a new unit. In addition, when new units are added, the condensers can be configured for closed-cycle, reducing energy requirements (by substantially reducing the turbine backpressure energy penalty) and associated air emissions.

The three factors that led EPA to reject closed-cycle cooling as BTA (described below in Section E) are far less relevant for new units at existing facilities than for retrofitting existing units. This section discusses why EPA concluded that each factor is not a significant concern for new units, and why the record supports EPA's conclusion that closed-cycle cooling is an available and feasible technology for new units at existing facilities.

- Land Availability: In contrast to retrofitting the entire existing facility, the amount of space dedicated to closed-cycle for the new unit will be limited to the new unit rather than the entire facility. As a result, space constraints will be much less of an issue. New units also present the opportunity to design an optimized closed-cycle recirculating system for the new unit. Retrofitting an existing facility for the full intake flow of the facility would require a facility to identify (or possibly obtain) enough space to accommodate the cooling towers and associated equipment. Furthermore, new units and their corresponding cooling system can be built in stages rather than as a facility-wide retrofit, and since the new unit has not yet been built, there is no energy reliability concern (discussed further below).
- Air Emissions: EPA expects that emissions are significantly less of a concern at new units. The condensers will be optimized for closed-cycle, reducing energy requirements, and high-efficiency cooling towers can be incorporated into the design of the new unit, potentially allowing for smaller cooling towers to be installed. Turbine backpressure and the associated energy penalty can be substantially reduced in a new unit, but EPA acknowledges new units will still have auxiliary power consumption for fans. Therefore energy penalties and air emissions for tower operations can be minimized (though not eliminated). The emissions effects of requiring closed-cycle cooling at new units at existing facilities is similar to the effects of this requirement at new facilities and will not pose an unacceptable impact. For more information, see Chapters 6, 8, and 10 of the TDD. Further, the new unit is likely to be more efficient and emit less pollution than existing units, therefore net emissions are expected to decrease as new units replace older, less efficient units.
- Remaining Useful Plant Life: This is clearly not an issue for new units. A new unit has its full useful life remaining and thus would experience the maximum possible reductions in adverse environmental impacts throughout that useful life.

EPA does not expect that the requirements for new units at existing facilities will be a disincentive for facilities to repower existing units. The requirements only apply to stand-alone units. Requirements for entrainment at repowered units will thus be determined by the Director. EPA notes, however, for facilities that do choose to repower an existing unit, the costs of employing a closed-cycle cooling system are not a barrier, as described above. In fact, some facilities may find closed-cycle cooling to be less costly over the long-term. For example, in locations with limited water resources such that once-through cooling of an additional unit is not possible, overall reliability will be increased by using closed-cycle cooling systems.

EPA also recognizes that installing closed-cycle cooling systems at new units is a prevailing trend in industry, regardless of the regulatory requirements imposed by today's final rule. For example, see DCN 12–6672 in the record for today's rule, and DCNs 2–009 and 4–4023C (from the Phase I and Phase II dockets, respectively). These documents show that, on the basis of responses from facilities to the 316(b) industry questionnaire, facilities constructed in recent years are significantly more likely to employ closed-cycle cooling.

EPA recognizes that at some point in the future, every unit will be rebuilt, replaced or repowered (or retired). EPA projects that approximately 227 MW in new generating capacity per year, will be subject to the new unit provision, reflecting the general industry trend towards more efficient units. EPA's analysis projects an equivalent number of new units at manufacturing facilities will be constructed each year. See the Phase I rule for more information

[72] Note that these metrics are not explicit requirements for closed-cycle recirculating systems. They simply represent what EPA views as examples of characteristics of a properly operated and maintained closed-cycle recirculating system, as defined at § 125.92(c)(1).

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regarding the affordability and barrier to entry analysis for new construction.

EPA notes that the new unit provision is an important element of the final rule, given the generally long lifespan of equipment at industrial facilities. For example, generating units at a power plant are often projected to have a 50-year lifespan. As a result, these facilities have a slow rate of ''evolution'' in adopting newer technologies. By requiring closed-cycle cooling in new units, EPA is ensuring (along with the Phase I rule) that no new once-through cooling units or facilities will be built.

E. Option Selection

After considering all factors identified above, EPA has concluded that it should base the BTA impingement mortality standard for existing units on the performance of traveling screens (e.g., modified Ristroph screens and equivalent modified traveling screens with fish-friendly fish returns)—the ''best technology available'' for minimizing impingement mortality. While there are a number of technologies that may perform as well as or better than traveling screens, these technologies were not feasible or available on a nationwide basis and thus were not the ''best technology available'' for standard setting purposes. Moreover, the impingement mortality standard for existing units provides a number of alternatives, including some of these other technologies, for compliance with the standard. EPA based the BTA impingement mortality standard for existing units on the performance of traveling screens because EPA concluded that this technology is effective, widely available, feasible,[73] and does not lead to unacceptable non-water quality impacts.

As explained above, EPA has not identified a technology or combinations of technologies that EPA concluded is ''best technology available'' for minimizing entrainment at existing units. EPA did not identify a technology for reducing entrainment that is effective, widely available, feasible, and does not lead to unacceptable non-water quality impacts. As such, EPA is unable to identify a nationally applicable BTA technology on which to base the BTA entrainment standard.

While EPA concluded that closed-cycle recirculating systems reduce entrainment (and impingement mortality) to the greatest extent and are the most effective performing technology, after careful consideration of multiple factors, EPA concluded that a closed-cycle recirculating system is not the ''best technology available'' for existing units within the meaning of the statute. It is not the best technology available on a national basis for minimizing adverse environmental impact and should not form the sole basis for the BTA standard for entrainment for the reasons explained below.

EPA also determined that there were no other ''available'' technologies for entrainment whose performance came close to that of closed-cycle recirculating systems. Further, while reduced intake velocity was a very effective control for impingement and may also reduce entrainment of some life stages of fish and shellfish, it does not significantly reduce entrainment of eggs and non-motile stages of larvae, and it is not physically available in many locations.

EPA has broad discretion in what factors it should consider when it determines the best technology available for minimizing the adverse environmental impacts of cooling water intake structures. As both the U.S. Supreme Court and the Second Circuit Court of Appeals have underscored, section 316(b) is ''sui generis,'' in a class by itself, unencumbered by ''specified statutory factors,'' *Entergy Corp.* v. *Riverkeeper, Inc.,* 556 U.S. 208, 222 (2009); *Riverkeeper, Inc.* v. *EPA,* 358 F, 3d 174,187 (2d Cir. 2004). The Second Circuit explicitly rejected the argument that, because section 316(b) does not mention costs or other factors, EPA cannot give costs or other factors ''any'' weight in deciding what is the best technology. *Riverkeeper, Inc.,* 358 F.3d at 195. Furthermore, the Second Circuit recognized that EPA may base its decision on factors other than the effectiveness of a given technology in reducing impingement and entrainment and that EPA is entitled to deference in deciding what weight to give to the factors it considers in its BTA determination. *Riverkeeper, Inc.,* 358 F.3d at 196.

As noted, costs are one factor EPA may consider in its BTA determination. Here, while EPA did consider costs, costs were not a dispositive factor in the decision to reject closed-cycle cooling as the basis for a uniform national BTA entrainment standard. EPA did not reject closed-cycle cooling here either because it was not economically achievable or because the costs of closed-cycle would exceed its benefits. Instead, EPA rejected closed-cycle cooling as the technology basis for a uniform national BTA entrainment standard based on three factors: Land availability, air emissions, and remaining useful plant life as explained below.

Central to EPA's evaluation of the availability of closed-cycle as BTA was EPA's new understanding of the limitations of technologies other than closed-cycle in reducing entrainment. This presented EPA with a sharper choice than it had in the Phase II rule. For today's rulemaking, EPA took a second look at the data it had relied on in the Phase II rule, particularly in light of new data received since the Phase II rule. As a result, EPA learned that entrainment exclusion does not necessarily equate to entrainment survival (76 FR 22185), a key underpinning to EPA's BTA standards for entrainment in the remanded Phase II rule.

For the remanded Phase II rule, EPA had established national BTA performance standards for entrainment (and impingement) and included a number of different alternative means to achieve the standards. First, if a facility demonstrated that it could achieve reductions in flow associated with closed-cycle cooling, the facility met the BTA performance standards. Alternatively, a facility could demonstrate that it met the entrainment performance standards by a combination of installed technology and operational or other measures (including restoration measures). See 69 FR 41590 for a description of the final Phase II rule. Critical to EPA's decision to provide an array of choices for achieving the national BTA entrainment performance standards was a key factual conclusion. That conclusion was that a number of technologies would achieve performance reducing entrainment that was ''comparable'' to that of closed-cycle cooling. Consequently, for the Phase II rule, EPA established an entrainment performance standard of 60 to 90 percent based on data it reviewed for the Phase II rulemaking. See 69 FR 41598 for information on EPA's rationale for establishing compliance alternatives as part of the final rule.

In the Phase II rule, while EPA looked to the performance of closed-cycle as the benchmark against which it evaluated technologies for the BTA standards, EPA did not mandate the achievement of flow reductions that were in all cases equivalent to closed-cycle. Given that the available data supported the view that there were other much less expensive technologies that obtained significant reductions in entrainment, EPA was comfortable with a BTA standard that required achievement of a level of performance

[73] As part of the feasibility determination, EPA found that the costs associated with the IM standards are reasonable for the industry as a whole.

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that was generally comparable though not equivalent to closed-cycle.

Since the Phase II rulemaking, EPA has received new data and learned that its understanding of entrainment technology performance was incomplete. Following the remand of the Phase II rule, EPA reexamined the data as well as new information on the performance of various entrainment control technologies it had previously reviewed. As a result, EPA determined that its conclusion regarding the capability of these other technologies—a conclusion on which the Agency had based the Phase II BTA performance standards—was no longer supported by the data EPA had before it.

There is a second additional consideration that further required EPA to focus renewed attention on how widely available closed-cycle cooling in fact was nationally. The Second Circuit decision in the Phase II rule removed restoration as a compliance option that EPA could consider. The decision underscored that restoration measures—one compliance option included in the Phase II rule—were not an available tool for complying with any 316(b) standard. However, at the time of the Phase II promulgation, EPA expected some facilities would use restoration in lieu of closed-cycle cooling, thus making closed-cycle or reductions commensurate with closed-cycle feasible (76 FR 41609). With the court decisions that restoration was not an available tool for compliance, compliance with a standard based on closed-cycle cooling alone is less feasible than EPA had expected at the time of the Phase II promulgation.

The changed landscape has narrowed markedly EPA's range of options with respect to the technology basis for today's BTA standards. The gap between the performance of the most effective entrainment reduction technologies (closed-cycle) and other less expensive technologies has widened significantly. EPA's narrowed range of compliance technology choices required EPA to look even more closely at the feasibility of closed-cycle cooling and reduced flow. As the Second Circuit has noted, EPA is clearly entitled to make its choice among alternative BTA technologies based on more factors other than just a technology's effectiveness in reducing impingement and entrainment. *Riverkeeper, Inc.,* 358 F.3d at 196. EPA identified three factors as significant in its decision to reject closed-cycle cooling as the sole technology basis for a national BTA entrainment standard. The three factors that collectively support rejecting closed-cycle cooling systems as a uniformly applicable BTA for existing facilities (except new units) are land availability, increased air emissions and remaining useful life.

1. Land Availability and Geographical Constraints Could Be a Factor on a Local Basis

While EPA's record indicated that the majority of facilities have adequate available land to retrofit to closed-cycle cooling, some facilities have land constraints.[74] While EPA originally estimated as many as 23 percent of facilities would not have enough space,[75] it observed on site visits that some facilities with a small parcel of land could still install closed-cycle cooling by using creative engineering solutions. On the other hand, EPA found that some facilities with large acreage could not feasibly install cooling towers because of local zoning or other local concerns. Thus, existing physical space at the facility was not the only factor contributing to uncertainty about land availability. Further review has shown that setback distances to mitigate noise and plume abatement (based on GPS mapping of residential areas) act as an additional constraint on land available for retrofitting to closed-cycle, and the cost of acquiring new land may be prohibitive for some facilities. Consequently, EPA estimates that 25 percent or more of facilities might have one or more constraints on land availability that would limit the ability to retrofit for cooling towers for the entire facility. EPA lacks adequate support to indicate that land constraints can be accommodated at existing facilities.

EPA also attempted to determine criteria based on the data in its record that would enable it to define a threshold for determining land availability on a nationwide basis, but was unsuccessful. For example, one analysis explored a threshold of approximately 160 acres per GW (gigawatt) below which a facility could not feasibly install cooling towers. Based on acres and the footprint of the facility and its surroundings (primarily those sites for which EPA conducted site visits), EPA found such an approach did not accurately identify which facilities could feasibly install closed-cycle.

2. Increased Air Emissions Could Be a Factor on a Local Basis

As previously discussed, retrofitting closed-cycle cooling (without also repowering) would result in increased air emissions of various pollutants, including particulates, sulfur dioxide, nitrogen oxides, mercury, and greenhouse gases, among others.[76] As a result of installing closed-cycle cooling structures, fossil-fueled facilities would need to burn additional fuel, thereby emitting additional PM, CO_2, SO_2, NO_X, and Hg. Two factors are responsible: (1) The need to compensate for energy required for operating cooling towers, and (2) slightly lower generating efficiency attributed to higher turbine backpressure when the condenser is not replaced with one optimized for closed-cycle operation when retrofitting existing units (also referred to as the energy penalty). While both of these factors contribute to increased air emissions, the larger contributor to projected increased air emissions is by far the energy penalty.

The impact of the increased emissions varies according to the local circumstances. The increased emissions could consist of stack emissions from increased fuel usage, cooling tower emissions, and plumes of water vapor. EPA's analysis suggested that the most significant impacts would be increased $PM_{2.5}$ emissions, which are associated directly with an increase in human health effects. EPA notes that cooling plume abatement and drift elimination technologies exist to address cooling tower emissions (and EPA included costs for such technologies in its analysis of Proposal Options 2 and 3). Further, EPA expects most effects of the particulates from cooling tower emissions would be limited to the immediate vicinity, confined wholly to the facility property. (See DCN 10–6954.) Therefore, EPA's primary concern is increased air emissions associated with additional fuel usage due to the energy penalty when retrofitting to cooling towers. EPA's review of emissions data from E–GRID (year 2005) suggests that impacts from these pollutant discharges could be significant. These include the human health and welfare and global climate change effects—all associated with a

[74] For example, in the case of fossil fuel facilities, scrubber controls may already have been required to comply with air rules and standards. This may reduce available land for closed-cycle.

[75] EPRI reported at least 6 percent of sites it evaluated were deemed ''infeasible'' because no space was available on which to locate a cooling tower. (DCN 10–6951) While EPA does not have access to the facility level data, EPRI's report supports EPA's conclusion that there is significant uncertainty around space constraints for facilities to install closed-cycle cooling.

[76] EPA recognizes that retrofitting closed-cycle cooling could be combined with other energy efficiency or pollution control technologies with the net effect of reducing air emissions; however, facilities could (and may be required to under other rules) install such technologies anyway, without converting to closed-cycle cooling.

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variety of pollutants that are emitted from fossil fuel combustion. EPA is not able to quantify the frequency with which facilities could experience these local impacts, and therefore has concluded that the proper forum to address such local impacts fully is in a site-specific setting.

3. Remaining Useful Plant Life Could Be a Factor on a Facility Basis

A number of facilities are nearing the end of their useful life. Considering the long lead time to plan, design, and construct closed-cycle cooling systems, EPA determined that the Director should have the latitude to consider the remaining useful plant life in establishing entrainment mortality requirements for a facility. The remaining useful plant life, along with other site-specific information, will affect the entrainment reduction of closed-cycle cooling at a facility. For example, retrofitting to a closed-cycle system at a facility that is scheduled to close in three years will result in little entrainment reduction as compared to retrofitting to closed-cycle at a facility that will continue to operate for a significantly longer period.

The Decision To Establish a National BTA Standard Requiring Site-Specific Determination of BTA Entrainment Controls

Once EPA determined that a ''one-size-fits-all'' approach for entrainment for existing units is not generally feasible, it is appropriate to assess the required controls on a site-specific basis. Therefore, for existing units, EPA decided to adopt as the BTA entrainment standard an overarching regulatory framework under which the Director will establish BTA entrainment requirements on a site-specific basis following prescribed procedures and applying specified factors for decision-making prescribed in the regulation and as described below.

EPA concluded that site-specific proceedings are the appropriate forum for weighing all relevant considerations in establishing BTA entrainment requirements. Closed-cycle cooling is indisputably the most effective technology at reducing entrainment. Closed-cycle reduces flows by 95 percent and entrainment is similarly highly reduced. But given that EPA estimates that 25 percent of existing facilities may face some geographical constraints on retrofitting closed-cycle cooling and concerns about air emissions and the remaining useful life of a facility, EPA rejected the option of requiring uniform entrainment controls based on closed-cycle cooling. Instead, EPA elected to adopt as the entrainment standard a more flexible process in which, following consideration of a host of factors, the Director will prescribe 316(b) entrainment conditions appropriate at a particular site. For additional discussion on how a site-specific consideration of entrainment control requirements will be implemented, see Section VIII below.

EPA has several reasons for adopting the framework approach as the BTA standard for entrainment. As explained, the record shows that though closed-cycle cooling is effective, it is neither widely available nor feasible, and has significant unacceptable non-water quality impacts. While EPA cannot identify with precision the extent of these limitations on installing closed-cycle cooling systems nationwide, the record indicates that the circumstances are neither isolated nor insignificant. In light of this, EPA decided not to establish closed-cycle cooling as a presumptive BTA entrainment standard, pending a site-specific demonstration of the limitations. Instead, entrainment control requirements will be determined in a site-specific setting where the opportunity for local input in decision-making process will be maximized.

With regard to new units at existing facilities, based on the performance of properly operated cooling tower operation and the availability, feasibility and affordability of closed-cycle cooling at new units, EPA selected closed-cycle recirculating systems based on wet cooling towers as BTA. For a discussion of how the three factors (availability, feasibility and affordability) relate to new units, see Section VI.D.3. Consistent with the Phase I rule for new facilities, EPA has also included a compliance alternative allowing a facility to show performance comparable to that of a closed-cycle recirculating system. The new unit provisions in today's final rule are essentially the same as the requirements for new facilities under the Phase I rule.

F. Other Options Considered for Today's Final Regulation

EPA considered several other options for the BTA standards in developing today's rule, but ultimately rejected them. This section includes a discussion of these options, as well as some technologies that EPA considered, but did not include as compliance alternatives to the impingement mortality standards.

1. Proposal Option 4—Flexible Impingement Mortality Controls Similar to Final Rule at Existing Facilities With DIF of 50 mgd or More; BPJ Permits for Impingement Mortality and Entrainment at Existing Facilities With Design Intake Flow Between 2 mgd and 50 mgd; Site-Specific Entrainment Standard for Existing Facilities With DIF of 50 mgd or More; and Uniform Impingement Mortality and Entrainment Controls for All New Units at Existing Facilities Similar to Final Rule

At proposal, EPA's preferred option was Option 1, which was the option closest to today's final rule, and the starting point for the description of the changes to the rule in Section V above. At proposal, EPA also considered a variant of Option 1, called Option 4, which changed the impingement mortality requirements for facilities under 50 mgd from the performance standard in Option 1 to BTA as determined by best professional judgment. In the case of an existing facility below 50 mgd that added a new unit, the flow associated with the new unit would have been subject to the uniform entrainment requirements based on closed-cycle cooling. Finally, all existing facilities withdrawing more than 2 mgd of DIF would have been subject to entrainment requirements established on a site-specific basis, with the exception noted above for new units. The option analyzed here, called Proposal Option 4, is likewise similar to the final rule, but for the impingement standard based on BPJ for facilities between 2 and 50 mgd.

EPA ultimately rejected Proposal Option 4 because EPA found that the technologies on which the impingement mortality performance standard of today's final rule is based are available, feasible, demonstrated, and affordable for all regulated facilities on a national basis. Moreover, EPA's analysis showed that the difference in the total costs for the two options was nominal. Additionally, EPA notes that many facilities with a DIF under 50 mgd already use closed-cycle cooling and would have minimal burden under the final rule. These facilities would have no difficulty complying with the requirements EPA is establishing in today's final rule. Proposal Option 4, by not distinguishing between those facilities under 50 mgd that have already minimized adverse environmental impacts from those that have not, masks the actions that would have to be taken by the latter group to comply with today's final rule. In addition, the flexibilities introduced in the June 11, 2012 NODA and included

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in today's final rule applied to all facilities, rather than taking the Option 4 approach at proposal of providing for more Director discretion for only the smaller withdrawing facilities. EPA also concluded that the data collection activities required under the final rule will be more protective of threatened and endangered species because they provide information on a larger number of facilities than Proposal Option 4 for consideration by the Director in permitting decisions. Lastly, EPA acknowledges that Proposal Option 4 is more burdensome to permitting authorities than is the final rule, as it requires more case-by-case decision making.

2. Proposal Option 2—Flexible Impingement Mortality Controls Similar to Final Rule at All Existing Facilities That Withdraw Over 2 mgd DIF; Site-Specific Entrainment Standard for Existing Facilities With DIF at or Below 125 mgd; Require Flow Reduction Commensurate With Closed-Cycle Cooling by Facilities Greater Than 125 mgd DIF; and Uniform Impingement Mortality and Entrainment Controls for All New Units at Existing Facilities

As previously explained, EPA assessed a number of different technologies that reduce impingement mortality and entrainment as the possible basis for section 316(b) requirements. EPA concluded that closed-cycle recirculating systems (based on wet cooling towers) are the most effective technology for reducing impingement mortality and entrainment. Notwithstanding that conclusion, EPA has decided not to establish a performance standard for impingement and entrainment based on closed-cycle recirculating systems for existing facilities. Furthermore, EPA found that there are no other effective technologies for entrainment that are available nationally. As described previously, each of the three factors for rejecting closed-cycle cooling as BTA for entrainment would also apply in the case of Proposal Option 2, despite the smaller number of facilities that would be subject to a requirement to retrofit. The technology basis for entrainment mortality controls for facilities greater than 125 mgd DIF under this option would have been wet cooling systems. The constraints discussed above that are associated with retrofitting a large portion of the universe of affected facilities, led EPA to conclude that requiring closed-cycle cooling on a uniform basis scale was not appropriate for a national regulation.

EPA notes that it proposed multiple options that included closed-cycle, and solicited comment on all aspects of closed-cycle cooling. After fully considering all comments and data, EPA still finds closed-cycle cooling is not the ''best technology available for minimizing adverse environmental impact'' required by section 316(b). Because of a combination of concerns over feasibility/availability, air emissions, and remaining useful life of the facility, EPA has rejected closed-cycle recirculating systems as the basis for national impingement and/or entrainment controls. Nor is EPA able to identify a subcategory for which these concerns no longer apply. Moreover, the complex interaction of all of these factors at individual sites does not lend itself to other regulatory options that would require closed-cycle recirculating systems with an ''off ramp'' if any of the factors were shown to result in unacceptable impacts because this would create a presumption for closed-cycle cooling rather than an equal balancing of all relevant factors. EPA decided not to establish any presumptive BTA entrainment outcome. EPA finds the entrainment standards framework in today's final rule will provide a consistent, more efficient, and more effective approach than standards with an ''off ramp.''

3. Proposal Option 3—Flexible Impingement Mortality Controls at All Existing Facilities That Withdraw Over 2 mgd DIF; Require Flow Reduction Commensurate With Closed-Cycle Cooling at All Existing Facilities Over 2 mgd DIF

Proposal Option 3 was, in many ways, the same as requiring closed-cycle cooling at all existing facilities. As described above, each of the three factors for rejecting closed-cycle cooling as BTA for entrainment would apply with equal force for Proposal Option 3. As a result, EPA has concluded Proposal Option 3, similarly, is not appropriate as BTA for entrainment.

4. Proposal Option 4 Variant

EPA also considered a variant of Proposal Option 4. As compared to Proposal Option 4, this variant did not include flexible alternatives for complying with the BTA impingement mortality standards (including pre-approved and streamlined alternatives), but did adopt the 50 mgd threshold to determine those facilities for which the Director has more discretion in determining BTA via BPJ. EPA analyzed this option to directly compare the effects of introducing flexible IM compliance alternatives at all facilities (as the final rule does) to the effects of introducing greater Director discretion for a subset of facilities, via BPJ permitting (as the Proposal Option 4 variant does). The preferred option at proposal, Option 1, was estimated to be more costly than Option 4 (Option 1 was estimated to cost $384 annually as compared with $327 million annually for Option 4). Under the analysis supporting the final rule the EPA is adopting today, however, today's final rule is estimated to cost $275 million annually in comparison with an estimated cost of $284 million annually for the Proposal Option 4 variant. Thus, EPA has concluded that providing flexible alternatives for compliance with the BTA IM standard at all facilities is both more effective at reducing costs to society and more readily justified as best technology available as compared to the approach of introducing greater Director discretion for only a subset of facilities (below 50 mgd). Hence, EPA rejected the Proposal Option 4 variant, and the approach of introducing greater Director discretion for only a subset of facilities (below 50 mgd).

5. Proposal Option 2 Variant

EPA also considered a variation of Proposal Option 2 that would have used 125 mgd AIF rather than 125 mgd DIF as the threshold. However, as described above, EPA rejected Proposal Option 2 and, for the same reasons, rejected this variant of Option 2.

6. Site-Specific Approach To Addressing Impingement

Many commenters (primarily from manufacturing facilities) commented that EPA should adopt a site-specific approach to addressing impingement mortality, similar to that employed for entrainment. As a result, EPA also considered an approach that would have established both impingement mortality and entrainment requirements fully on a site-specific basis taking into account for the particular facility, among other factors, those previously described as pertinent to EPA's 316(b) BTA determination. EPA rejected a fully site-specific approach for impingement controls principally because low-cost technologies for impingement mortality are available, feasible, demonstrated, and affordable for facilities nationally. Because technologies are available, a fully site-specific approach would place an unnecessary additional burden on state permitting resources. Moreover, the final impingement mortality standard includes several alternatives that allow site-specific demonstration that a particular technology performs at a level representing the best technology available for the site. EPA is instead promulgating a modified version of the

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proposed rule, adding several elements of flexibility (i.e., compliance alternatives), and thus directly addressing many of the concerns raised by these commenters.

7. Pre-Approved Technologies

Many commenters requested that EPA pre-approve technologies that, once installed, would obviate the need for further regulatory conditions such as periodic monitoring. This is similar to the approach taken for cylindrical wedgewire screens in the remanded 2004 Phase II rule (see 69 FR 41693). EPA has adopted, in significant measure, commenters' suggestion in the BTA impingement mortality standard in today's rule by including several pre-approved and several streamlined compliance alternatives in the form of technologies that may be approved following a demonstration of required performance, so long as the facility shows that its alternative technology is operating in a manner that minimizes adverse environmental impacts. As an option for achieving the impingement mortality standards, a facility may install and operate specified impingement controls whose performance is comparable to or better than the technology EPA concluded was the ''best technology available'' for impingement mortality reductions:

- Closed-cycle recirculating systems, defined at § 125.92(c)
- Existing offshore velocity caps, defined at § 125.92(v)
- Technologies that result in a design intake velocity less than or equal to 0.5 fps, including most modern cylindrical wedgewire screens

Although this rule leaves the BTA entrainment determination to the Director, with the possible BTA decisions ranging from no additional controls to closed-cycle recirculating systems plus additional controls as warranted, EPA expects that the Director, in the site-specific permitting proceeding, will determine that facilities with properly operated closed-cycle recirculating systems do not require additional entrainment reduction control measures. Refer to Section E.1 for the EPA's rationale for selecting these controls.

G. Final Rule BTA Performance Standards

The rule establishes the following BTA standards for Impingement Mortality and Entrainment: Impingement Mortality Standards at All Existing Units at Existing Facilities that withdraw greater than 2 mgd DIF; an Entrainment Standard that requires site-specific entrainment controls determined by the Director for Existing Units at Existing Facilities that withdraw over 2 mgd DIF; BTA standards for impingement mortality and entrainment for new units at existing facilities. The previous section described the other options that EPA considered but ultimately rejected, and the basis for those decisions.

1. Impingement Mortality Controls for Existing Units at Existing Facilities for the Final Rule

Today's final rule provides a facility a number of alternatives for complying with the BTA impingement mortality standard. As discussed more below, EPA's BTA impingement mortality standard is based on EPA's conclusion that, on a national basis, modified traveling screens with fish-friendly return systems are the best performing technology available for impingement mortality reduction. But EPA is not requiring compliance with the BTA impingement mortality standards only through monitoring data that demonstrates achievement of the numeric reduction in mortality levels that EPA has determined well-operated modified traveling screen will achieve. Rather, the final rule allows facilities to comply by employing any of seven alternatives, including monitored compliance with a numeric impingement mortality performance standard.

Based on its review of available data and information submitted by commenters, EPA identified a number of other technologies and operational measures that could achieve equivalent, or better, performance to the impingement mortality reductions achieved with modified traveling screens that may be available for some sites. Thus, the final rule provides seven alternatives for complying with the BTA impingement mortality standards. These include three compliance paths based on pre-approved technologies, and three compliance paths that offer a streamlined approach to compliance. EPA expects the majority of facilities will use one of these six options to comply with the BTA impingement mortality standards (see Exhibit VIII–1 for more information).

The following pre-approved technologies will comply with today's rule and are associated with minimal monitoring and reporting of operational and/or design parameters. These technologies are (the numbering reflects the numbering in § 125.94(c)): Operating (1) a closed-cycle recirculating system; (2) a cooling water intake structure that EPA or the State NPDES permitting authority determines has a design maximum through-screen intake velocity of 0.5 feet per second; or (4) an existing offshore velocity cap. The general intent behind a compliance path based on a pre-approved technology is to provide a level of certainty to the regulated entity that they would be deemed compliant with the relevant rule requirements by designing, installing, and operating the technology as specified in the regulation. The three pre-approved compliance alternatives are each based on a particular technology approach. The permit for each compliance alternative will necessarily include criteria, design standards, and operational conditions specific to the pre-approved technology. The compliance paths based on pre-approved technologies in today's final rule include simplified permit application requirements (such as reduced or minimal study), documentation, or reduced monitoring, and will therefore result in greatly simplified implementation. In today's final rule, there are no biological compliance monitoring requirements for any of the three compliance paths based on pre-approved technologies.

Under the streamlined alternatives, a facility must demonstrate to the Director that traveling screens or some combination of technology controls or operational measures represent BTA performance under the conditions at the site. The three streamlined compliance alternatives are (the numbering reflects the numbering in § 125.94(c)) operating (3) a cooling water intake structure that EPA or the State NPDES permitting authority determines has an actual maximum through-screen intake velocity of 0.5 feet per second; (5) modified traveling screens whose demonstrated performance represents the best technology available for impingement reduction at the site; or (6) a system or combination of technologies or operational measures whose demonstrated performance is the best technology available for impingement reduction at the site. In order to demonstrate BTA performance, a facility will need to conduct a two-year site-specific study at the same time it conducts its source water characterization and Entrainment Characterization Study. This study must demonstrate that its modified traveling screens, or combination of technology controls and operational measures, have been adjusted and optimized so as to minimize impingement mortality. If the Director concludes that the facility has demonstrated optimized performance for its controls, the facility will have no

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subsequent biological monitoring and reporting requirements as compared to a facility that complies using the impingement mortality performance standard. If the screens or other measures are not already installed, the Director may approve postponing the two-year study to be conducted after the entrainment determination has been made. These three streamlined compliance alternatives are based on a technology or suite of technologies and practices with more variable performance, and as such necessitate some degree of study, in order to optimize technology performance for the site-specific conditions encountered by a facility. A streamlined compliance alternative may require some level of monitoring, but once the optimal performance of the technology has been identified, conditions included in the permit specifying optimal operation ensure that the streamlined alternative is similar to or better than the impingement mortality performance standard. For example, the streamlined compliance alternatives also do not require biological compliance monitoring.

The seventh alternative (at § 125.94(c)(7)) for complying with the BTA impingement mortality standards requires the owner or operator to demonstrate compliance with the numeric impingement mortality performance standard through biological monitoring. Under this alternative, the owner or operator has the flexibility to choose any technology, including a new or innovative technology, provided the compliance monitoring demonstrates the performance standard is achieved.

Each of these seven alternatives is further described below. In addition, further discussion of how each of these alternatives will be implemented may be found in Section VIII.

a. Closed-Cycle Recirculating Systems

As described above, in Chapter 6 of the TDD, and in prior rulemakings, EPA has long recognized the benefits of flow reduction from closed-cycle recirculating systems for reducing impingement (as well as entrainment). A facility employing a closed-cycle recirculating system will typically reduce impingement by more than 95 percent. As a result, a facility may choose to comply with the BTA impingement mortality standards in today's final rule by demonstrating that it uses a properly operated and maintained closed-cycle recirculating system.

EPA estimates that approximately 18 percent of intake structures (i.e., those that already have an existing closed-cycle recirculating system, plus facilities located in California and New York, whose State regulations are at least as stringent as the final rule) will choose this alternative.

EPA does not have the data to determine precisely which impoundments are serving as part of a closed-cycle recirculating system as defined at 40 CFR 125.92(c)(2). However, EPA is aware that some facilities have created their impoundments in a water of the U.S. as part of their cooling system. EPA does not intend to eliminate the use of such lawfully created impoundments for their intended purpose, as doing so could result in a large number of stranded assets. If the cooling system with the impoundment minimizes the withdrawal of make-up water for cooling purposes, the Director may determine the cooling system meets the definition of a closed-cycle recirculating system.

b. Reduced Intake Velocity

EPA has long recognized the relationship between impingement and intake velocity. EPA conducted an analysis of fish swim speeds in the Phase I rule (see 66 FR 65274, December 18, 2001) and concluded that a design through-screen velocity of 0.5 fps is protective of 96 percent of motile organisms. However, EPA did not select intake velocity as the technology basis for the BTA impingement mortality standards. Although the performance of 0.5 fps intake velocity achieves greater reduction in impingement mortality than the technology on which the BTA impingement mortality standards are based, reducing a facility's intake velocity is not widely available or feasible for all existing facilities (see Chapter 6 of the TDD).

EPA is including reductions in intake velocity as an alternative for complying with the BTA impingement mortality standards through reduced intake velocity. A facility choosing this alternative must demonstrate that (1) the through-screen design velocity could not exceed 0.5 fps or (2) the actual intake velocity does not exceed 0.5 fps.

EPA estimates that approximately 34 percent of intake structures will choose this alternative. This estimate includes facilities that have an existing intake velocity of 0.5 fps or less, plus those facilities that are projected to install a technology that would reduce their intake velocity (larger intake, wedgewire screens, or variable speed pumps).

i. Design Intake Flow Basis

Consistent with EPA's determination in its earlier 316(b) regulatory efforts, the final rule allows a facility to comply with the BTA impingement mortality standards by demonstrating that its intake has a maximum through-screen design velocity of 0.5 fps. EPA concluded that facility's operating at this through-screen design velocity will protect the vast majority of impingeable aquatic organisms. Facilities choosing to comply with the BTA impingement mortality standards may not average velocity across multiple intakes at a facility.

ii. Actual Intake Flow Basis

EPA is also adopting a provision to allow facilities to demonstrate that the through-screen intake velocity at an intake structure does not exceed 0.5 fps on the basis of the intake's actual flow. (Again, note that facilities choosing this compliance alternative may not average intake velocity across multiple intakes.) In contrast to design flow above, a facility with an intake having a design through-screen intake velocity greater than 0.5 fps may be operated at a reduced capacity and therefore may withdraw cooling water at a velocity less than 0.5 fps. As long as the actual intake flow is such that the velocity remains at or below 0.5 fps, the reductions in impingement (and subsequently, impingement mortality) remain the same as a facility with a maximum design through-screen intake velocity of 0.5 fps. As described below, a facility will be required to monitor its intake flow and report this data to the Director to verify that intake flows do not exceed 0.5 fps. This approach also permits the Director to allow brief periods where the intake velocity will exceed 0.5 fps under extreme conditions.

c. Existing Offshore Velocity Caps

A number of commenters stated that EPA should consider existing offshore intakes fitted with velocity caps to be pre-approved and complying with the BTA impingement mortality standards. Locating submerged intakes in the deeper regions of larger waterbodies (particularly outside the littoral zone [77]) has the potential to reduce both impingement and entrainment (I&E), due to the lower densities of aquatic organisms as compared to a shoreline-based intake. EPA has identified 11 facilities with offshore velocity caps, and reviewed a number of studies documenting the performance of these

[77] The littoral zone extends from the shoreline to roughly the edge of the continental shelf.

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facilities. These studies show that the impingement reduction performance of intakes submerged far offshore with velocity caps is dependent on site-specific conditions. The data show that solely locating an intake far offshore (i.e., without also employing a velocity cap) achieves a 60 to 73 percent reduction in impingement, and therefore does not achieve impingement mortality reduction comparable to that of well-operated modified traveling screens. Similarly, the data also show that velocity caps alone achieve a 50 to 97 percent reduction in impingement, and therefore could result in compliance performance comparable to or better than modified traveling screens in some, but not in all cases. However, the combination of an existing intake located far offshore (i.e., approximately 850 feet, as identified in the data for Nine Mile Unit 1 and Oswego Unit 5) in combination with use of a velocity cap will result in performance that exceeds the 12-month average impingement mortality performance standard (alternative seven described above).[78] [79] Because there is some amount of uncertainty in measuring distances from a shoreline, including but not limited to due to variations in water levels, storm swells, or tidal excursions, EPA has set the minimum distance offshore at 800 feet. As a result, the final rule at § 122.95(c)(4) allows a facility to comply with the BTA impingement mortality standards with an existing offshore intake with an existing velocity cap located at least 800 feet offshore, based on the performance data from the 11 identified facilities.

As noted above, the record shows all existing facilities with a velocity cap located at least 800 feet offshore will meet or exceed the 12-month average mortality performance standard of § 125.94(c)(7). EPA does not have data showing velocity caps located at lesser distances offshore will consistently achieve the impingement mortality performance standards, but is aware that some facilities may be able to achieve the impingement mortality standards through a combination of technologies that includes an offshore location. For example, the Office of Naval Research states that the littoral zone in ocean environments generally extends from the shore to 600 ft out in the water (ONR 2013). SEAMAP data in EPA's record shows installing the intake to depths where there is a lower concentration of living organisms (i.e., at least 65 feet) is also expected to decrease environmental impacts associated with intake operations. Therefore, the final rule allows facilities with intake structures at significant distances offshore to demonstrate the performance of their technology under § 122.95(c)(6), as further discussed below.

In addition facilities may opt to construct an offshore velocity cap at new locations. In those circumstances, the facility will need to demonstrate that theperformance of its velocity caps is the best technology available for impingement reduction under the alternative found at § 122.95(c)(6). For more information, see DCN 12–6601.

EPA estimates that approximately 1 percent of intake structures (i.e., those with an existing velocity cap meeting the definition at § 125.92(v) will choose this alternative.

d. Install Modified Traveling Screens

In the June 11, 2012 NODA, EPA discussed a streamlined compliance option that would provide facilities with a less burdensome alternative than the proposed rule. In the final rule, EPA has included an option at § 125.95(c)(5) for facilities that install traveling screens—the technology that forms the basis for the numeric IM performance standards. Under this option, the facility must demonstrate to the Director that it will install and operate modified traveling screens as defined at § 125.92(s) that are or will be optimized to minimize IM mortality at the site. The facility will also be required to submit an impingement technology performance optimization study (§ 122.21(r)(6)) which will include a 2-year optimization study for the intake technology. The facility will conduct 2 years of monthly impingement data collection, during which the facility will seek to optimize the technology performance to minimize impingement mortality. This study is intended to determine the optimal configuration and operating conditions of modified traveling screens and the fish handling and return systems for that intake to be consistently protective of aquatic organisms. During the course of the study, EPA expects that a facility will evaluate the interim results and make changes to the technology or operating conditions as needed to identify the most appropriate set of operational characteristics to ensure long-term success. For example, a facility could adjust the spray wash pressure, adjust the rotating speed of the screens, rotate the screens more frequently, re-angle the fish sluicing sprays, ensure adequate water in the return flume, design the fish return to avoid avian and animal predation on the aquatic organisms, and locate the fish return in such a way to avoid predation. Once a facility has optimized its technology performance, the study will identify operational measures that will serve as observable and enforceable permit conditions. As evidenced by the data used in determining the performance standard, by requiring facilities to study the conditions for optimized performance, many facilities will achieve impingement mortality reductions much greater than the 12-month average impingement mortality performance standard without significant additional investment. Biological data collection beyond this two-year study will not be required. The facility will simply be required to ensure that it is operating its technology under the identified conditions for optimized performance. If the Director concludes that the screens will achieve optimized performance, the Director will also incorporate operating conditions to ensure optimized performance as terms of the facility's NPDES permit.

As discussed in the NODA and Chapter 4 of TDD, EPA's data indicate that most facilities employ traveling screens.[80] EPA anticipates that, as a result, many facilities will view the streamlined screen-based compliance route as a logical choice for complying with the final rule. The streamlined option provides an opportunity for a large number of the affected facilities (i.e., those that do not meet the criteria for the other compliance technologies) to demonstrate that their intakes are effectively reducing impingement mortality while significantly reducing the burden on both facilities and regulatory agencies. EPA estimates that approximately 30 percent of intake structures will choose this alternative.[81]

EPA is aware that some facilities have no technologies installed and will choose to install modified traveling screens, and further that some facilities

[78] An existing facility may also choose to install a new offshore intake with a velocity cap, but such a facility would not automatically qualify as meeting the impingement requirements for the final rule. Such a facility would need to demonstrate equivalent performance to the impingement mortality performance standard.

[79] A velocity cap must also include bar racks or other devices to exclude large marine organisms (e.g., seals, turtles) from entering the intake structure.

[80] EPA's technical survey found that 93 percent of electric generators and 73 percent of manufacturers already use screens, the majority of which are traveling screens.

[81] While EPA's data shows 73 to 93 percent of facilities already use traveling screens, EPA notes that many facilities use more than one technology. For example, some of these facilities also have a low intake velocity, an offshore velocity cap, or cooling towers. EPA expects facilities will choose the IM compliance alternative corresponding to these pre-approved technologies before they will choose to comply via optimized performance of their traveling screens.

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with traveling screens will choose to either retrofit to modified traveling screens with fish handling and returns. Obviously, the impingement technology performance optimization study cannot be undertaken until the technology is first installed. In this case the NPDES permit would be issued before the completion of the optimization study. EPA expects a permit will be issued that includes a schedule for both the technology installation and the required optimization study. As discussed earlier, the Director can establish interim measures as appropriate (40 CFR 125.94(b)).

e. System of Technologies as the BTA for Impingement Mortality

EPA recognizes that cooling water intake structures have a variety of configurations and facilities may choose to comply with the final rule by using more than one of the compliance approaches outlined above. In the June 11, 2012, NODA, EPA described an approach where facilities would be able to demonstrate ''credit'' toward meeting the impingement mortality requirements by reducing the total number of organisms impinged. EPA also intended for facilities to have the flexibility to employ any system of technologies or combination of operational measures to address impingement mortality so long as the performance of the selected impingement reduction measures represented the best technology available for the site. The final rule includes an alternative reflecting these objectives.

In the broadest sense, facilities have a number of options for reducing impingement mortality. Some may choose to comply using an approach where a single technology achieves the level of compliance necessary. Others may choose an approach of employing multiple technologies or operational measures, including reducing the number of organisms that are impinged or susceptible to being impinged. The following are examples of approaches for which a facility might be able to take credit for impingement reduction under this alternative:

- Partial closed-cycle cooling
- Variable speed pumps
- Seasonal outages (including standard maintenance outages that are specifically scheduled to avoid a biologically sensitive period)
- Certain impingement technologies that reduce the number of organisms exposed to the intake structure (e.g., diversions, louvers, barrier nets)
- Intake location
- Behavioral technologies (e.g., light or sound barriers) [82]

In each case, the technology employed reduces the number of organisms that potentially are impinged, resulting in a reduction in the number of organisms actually impinged (i.e., a reduction in the rate of impingement). By virtue of reducing the actual impingement, mortality caused by impingement is no longer a consideration—an organism that is never impinged cannot be killed by the intake structure. Some technologies work to reduce the intake flow, thereby reducing the potential organisms exposed to the intake. Others work to divert organisms away from the screens, either through a physical exclusion or by being placed in a less biologically productive area. EPA concluded that it is appropriate to recognize these reductions in impingement as a step in achieving a BTA impingement mortality reduction performance at a particular site. As a result, EPA expects the reduction in impingement will be treated as an equivalent reduction in impingement mortality, and will therefore be considered by EPA or the State NPDES permitting authority in evaluating whether the chosen technologies and operational measures represent BTA performance under the site's conditions. For example, an intake that operates infrequently due to the infrequent operation of the electric generating unit(s) it serves (such as a peaking unit) may use a relatively small amount of water on an annual basis when compared to the design capacity of the intake structure. This facility may choose to comply with the impingement mortality standard at § 125.94(c)(6) by demonstrating to the Director that the facility operates at an annual intake flow that is less than or equal to 24 percent of its design intake flow on an annual basis. This level of flow reduction could achieve a level of performance equivalent to or better than the impingement mortality performance standard in § 125.94(c)(7), and therefore could be considered to be compliant with the requirements of today's final rule. This demonstration may include design data, several years of past operating data, and dispatch modeling. These operating conditions would then be incorporated into the NPDES permit.

A facility complying under this part, must submit a impingement technology performance optimization study, which must include the calculated percent impingement mortality reflecting optimized operation of the system of technologies, operational measures, and best management practices and all supporting calculations. Total system performance is the combination of impingement mortality performance reflected in all of the following which apply:

- Rate of impingement—The estimated reductions in rate of impingement must be based on a comparison of the system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody. For impoundments that include waters of the United States, the facility's rate of impingement must be measured at a location within the cooling water intake system that the Director deems appropriate.
- Impingement mortality—If the demonstration relies in part on a credit for reductions in impingement mortality already obtained at the facility, two years of biological data collection must be provided, demonstrating the level of impingement mortality the system is capable of achieving.
- Flow reduction—If the demonstration relies in part on flow reduction to reduce impingement, the data must include two years of intake flows, measured daily, as part of the demonstration. This must include documentation of how the flow reduction results in reduced impingement.

The permitting authorities would consider this information shown in the two-year impingement technology performance optimization study that must be submitted under this alternative. For example, at facilities choosing to comply by demonstrating that they are operating below 24 percent of their intake capacity, or that they are peaking units, the Director should use this study to establish operating conditions that ensure that the intake continues to operate below 24 percent of its intake capacity or continues to serve only peaking units and that these units are not later used as intermediate or baseload units. The operating conditions and parameters identified in the study will then be incorporated in the facility's permit conditions. EPA estimates that approximately 17 percent

[82] For example, anadromous clupieds such as alewife, blueback herring, and American shad have demonstrated avoidance behaviors when exposed to high frequency sound. Deployments of this technology at Entergy's FitzPatrick Nuclear Station on Lake Ontario have resulted in a reduction of over 90 percent in impingement of alewife. In this case, EPA expects the Director would determine that impingement requirements regarding alewife have been addressed by the acoustical deterrent. The Director could disallow such a technology if it were deemed to have a negative effect on threatened or endangered species whose habitat includes the facility's intake location.

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of intake structures will choose this alternative.

f. Comply With the Numeric Impingement Mortality Performance Standard

Facilities complying with the BTA impingement mortality standard by achieving the numeric performance standard at § 125.94(c)(7) will perform monthly compliance monitoring to verify that the 12 month percent impingement mortality resulting from operation of its intake is below the standard established in today's final rule. (For more details on complying with the impingement requirements, see Section VIII.) EPA expects that, save for future technologies or innovations, few facilities will avail themselves of this option.

2. Entrainment Controls for Existing Units at Existing Facilities

The BTA entrainment standard for the final rule establishes a framework under which EPA or the State NPDES permitting authority must establish site-specific BTA entrainment requirements for each facility in the scope of today's rule. EPA considered promulgating no further controls to address entrainment mortality, and to rely instead only on the BTA impingement mortality controls, which would achieve up to a 34 percent reduction in total AEI. EPA did not select this option as the basis for national BTA because, in EPA's view, some facilities either are having a significant impact as a result of entrainment or might be able to do more to control entrainment at costs that are low relative to benefits. In addition, EPA's data on entrainment at facilities are not sufficient to allow the Agency to categorize facilities requiring no additional controls for entrainment. Thus, the final rule by requiring prescribed information in the permit application will provide the Director with adequate information for decision making. Requiring a structured site-specific analysis of candidate BTA technologies for entrainment control will allow the Director to determine where it is appropriate to require such controls. One outcome of the site-specific analysis could be that the Director would determine that no other technologies beyond impingement controls are required for BTA entrainment reductions, either because they are not feasible or because the social costs of additional control measures are not justified by the social benefits.

In the case of site-specific entrainment controls for facilities withdrawing greater than 125 mgd AIF, the final rule requires facilities to also develop and submit an Entrainment Characterization Study and related supporting information, as described in § 122.21(r)(9)–(13) of today's rule, for use by the Director in establishing site-specific BTA. For facilities above 125 mgd AIF that also meet the definition of closed-cycle recirculating systems at § 125.92(c), the Director may reduce or waive some or all of this information.

EPA considered simply requiring this information of all facilities above 125 mgd AIF without authorizing Directors to reduce or waive this information. However, EPA also recognizes that, in some instances, these same facilities have already minimized adverse environmental impacts significantly. In such cases, there may be limited value to the Director requiring a full benefit-cost analysis, or even obtaining the Entrainment Characterization Study at § 122.21(r)(9).

EPA also considered not requiring this information of any facilities above 125 mgd AIF meeting the definition at § 125.92(c). First, EPA noted that even though these facilities meet the definition of a closed-cycle recirculating system, they may still withdraw at least 125 mgd, and in some instances withdraw considerably more than 125 mgd. This is not an insubstantial volume of water withdrawn for cooling, and in the case of inland waters this withdrawal may comprise a large proportion of that source waterbody. In addition to withdrawing large volumes of water, EPA recognizes that some facilities, particularly those meeting the definition at § 125.92(c)(2), potentially withdraw water at a rate similar to a once-through facility not withdrawing from an impoundment, with the potential to cause adverse environmental impacts similar to those of once-through cooling. The Director may find the information in § 122.21(r)(9)–(13) to be useful in determining whether additional controls are warranted. In these instances, the Director may decide to require the Entrainment Characterization Study at § 122.21(r)(9) first, in order to determine if other studies in § 122.21(r)(10) to (13) are also warranted.

Facilities at or under the 125 mgd AIF threshold must still provide certain information under the permit application requirements at § 122.21(r). The Director may require additional information from these facilities including some or all of the studies at § 122.21(r)(9)–(13) if there is reasonable concern regarding entrainment impacts at the facility. Where an owner or operator of a facility intends to comply with the BTA standards for entrainment using a closed-cycle recirculating system as defined in § 125.92(c), the Director may reduce or waive some or all of this information.

Facilities with a closed-cycle recirculating system as defined at § 125.92(c)(2) would still submit the studies at § 122.21(r)(9)–(13) if they withdraw greater than 125 mgd AIF, and if the Director has not waived the requirements. These facilities have cooling systems that include impoundments of waters of the U.S. where the impoundment(s) was constructed prior to October 14, 2014 and lawfully created for the purpose of serving as part of the cooling water system. This purpose must be documented to the Director's satisfaction in the project purpose statement of any required Clean Water Act section 404 permit obtained to construct the impoundment. In the case of an impoundment whose construction pre-dated the CWA requirement to obtain a section 404 permit, where alternative permitting documents were required, the facility must document the project's purposes to the satisfaction of the Director by some other license or permit obtained to lawfully construct the impoundment for the purposes of a cooling water system. EPA notes that for impoundments constructed in uplands or not in waters of the United States, no documentation of a section 404 or other permit is required. EPA received comments that such impoundments should be treated as closed-cycle cooling and has agreed to make this change. The Director would still make the determination that make-up water withdraws have been minimized. Further, EPA's data shows that many facilities that utilize impoundments as part of their cooling water systems may actually use a combination of cooling water systems (for example, detailed survey responses showed eight facilities with an impoundment in addition to other IM technologies). The requirement that these facilities provide the Director with certain information will help ensure that the Director has adequate information upon which to base a decision for these impoundments as to whether these facilities have adequate controls already or should be taking additional measures to protect the relevant waterbody.

The Entrainment Characterization Study will include information already collected to meet existing § 122.21(r)(4) requirements. In addition, under the permit application requirements being added today at § 122.21(r)(5) to (13), the facility will submit certain additional site-specific information. This will include an engineering study of the

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technical feasibility and incremental costs of candidate entrainment mortality control technologies. The facility will also study, evaluate, and document the technical feasibility of technologies, at a minimum, including closed-cycle cooling, fine mesh screens with a mesh size of 2 mm or smaller, and water reuse or alternate sources; engineering cost estimates of all technologies considered; any outages, downtime, or other effects on revenue along with a discussion of all reasonable attempts to mitigate these cost factors; and a discussion of the magnitude of water quality and other benefits, both monetized and nonmonetized, of the candidate entrainment mortality reduction technologies evaluated. Finally, the information must include a discussion of the changes in non-water quality environmental impacts attributed to technologies and/or operational measures considered. The factors include, for example, increases and decreases in the following: Energy consumption, and air pollutant emissions including particulates and associated human health and global climate change impacts, water consumption, noise, safety (e.g., visibility of cooling tower plumes, icing), grid reliability, and facility reliability. For a thorough discussion of these study requirements, see Section VIII. The final rule also requires peer review of the Comprehensive Technical Feasibility and Cost Evaluation Study, Benefits Valuation Study, and Non-Water Quality and Other Impacts Assessment. Peer review of the Entrainment Characterization Study is not required. Note that the peer reviewed studies will rely on data gathered in the Entrainment Characterization Study. Peer reviewers will be selected in consultation with the Director, who can also consult with EPA and Federal, State, and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure(s).

Under the final rule, EPA expects that the Director will review the candidate technologies for entrainment mortality control that, at a minimum, includes closed-cycle recirculating systems, fine-mesh screens with a mesh size of 2 mm or smaller, and water reuse or alternate sources. In the decision about what additional entrainment controls (if any) to require, the Director will consider all the facility-specific factors in § 125.98(f)(2) and described above. At a minimum, the Director must provide a discussion explaining how issues concerning air emissions or land availability, insofar as they relate to the feasibility of adoption of an entrainment technology, and remaining useful plant life, were addressed in the site-specific determination. Under the final rule, the Director must issue a written explanation for the basis of the BTA entrainment determination for each facility. The Director's decision must include a written explanation that, at a minimum, includes consideration of the following factors: (i) Numbers and types of organisms entrained; (ii) impact of changes in particulate emissions or other pollutants associated with entrainment technologies; (iii) land availability inasmuch as it relates to the feasibility of entrainment technology; (iv) remaining useful plant life; and (v) social costs and benefits, which may include qualitative, quantified and monetized categories. The Director may also base the proposed determination on several other factors, including thermal effects and water consumption.

In addition to the information required for development of impingement controls discussed above, the regulation also requires, in the case of facilities withdrawing greater than 125 mgd AIF, submission of certain other information for use in the site-specific entrainment determination of BTA. The final rule also adds the permit application requirements at § 122.21(r)(9)–(13) to require the facility to prepare several studies, including an Entrainment Characterization Study, that will fully characterize the extent of entrainment at the facility. (For more details about the study, see above). In addition, under the final rule, the facility will provide detailed information on the other factors relevant to the Director's site-specific BTA determination. These will include information concerning the technologies available for control of such entrainment, the costs of controls, the non-water quality environmental impacts of such controls, the monetized and nonmonetized benefits of such controls, and the presence of any threatened and endangered species. The final rule does not limit the Director's discretion to consider non-water quality impacts in determining whether further entrainment measures are justified. EPA encourages, and the CWA requires, the public to have a role in the permitting process. Interested members of the public may submit written comments on a draft permit during the 30 day public notice and comment period and request a public hearing on a draft permit. For permits that are issued by EPA instead of a state, additional opportunities for public involvement include comment, and in some cases, a public hearing on a permittee's State Water Quality Certification under section 401 of the CWA. (See 40 CFR 124.10, 124.11, 124.12(a) and 124.17(a).) Therefore, the final rule clearly affords the public a meaningful opportunity for participation in the site-specific decision making to help ensure the soundness of both the information and subsequent determinations.

H. Economic and Benefit Analysis for the Final Rule

1. Economic Justification for the Final Rule

Pursuant to the principles in E.O. 12866 and E.O. 13563, EPA has assessed costs and benefits for the final rule and has reasonably determined that the benefits of the rule justify the costs. EPA has estimated the social cost of this rule to be $275 million annually. For more information on EPA's analysis of the rule's costs, see Section IX.

As described in more detail below in Section X, significant benefits are associated with the rule. These benefits include the annual reduction in impingement mortality of 652 million age-one equivalents for existing units. There are, in addition, other important benefits, many of which EPA cannot quantify. These benefits include effects on many shellfish species and nonuse values associated with the vast majority of fish and shellfish. The rule also requires establishing site-specific entrainment controls through a process in which specific environmental conditions and the localized benefits of entrainment reductions will be assessed along with the costs of controls. The information generated in the required studies will enhance the transparency of decision making and provide an opportunity for meaningful public participation, ensuring that decision making is based on the best available data. Overall, these requirements and subsequent Director actions under this rule will foster protection and restoration of healthy aquatic ecosystems that have important commercial, recreational, aesthetic and cultural values to their surrounding communities. Many of the benefits that will result from the rule are not monetized or quantified, and as a result the Agency's monetized benefits analysis underestimates the totality of the rule's benefits. On the basis of the record, EPA has determined that the impingement mortality and entrainment controls will result in benefits that justify the costs of the rule.

EPA also notes that it was able to generate only a partial estimate of

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benefits for today's rule. In particular, EPA's analysis does not fully quantify or monetize certain potentially important categories of benefits, such as existence values for threatened and endangered species, secondary and tertiary ecosystem impacts, benthic community impacts, shellfish impacts and the impacts arising from reductions in thermal discharges that would be associated with closed-cycle cooling. Changes in fish assemblages due to impingement, entrainment and thermal effects are also not fully valued. These categories of benefits which are not fully valued are often referred to as nonuse benefits—i.e., benefits that people derive apart from using an affected resource, such as fishing. For example, nonuse benefits would include the value that individuals place on knowing that an aquatic ecosystem is healthy. EPA conducted a nonuse benefits transfer was based on a species that represents less than one percent of adverse environmental impacts. EPA developed and implemented an original stated preference survey to estimate total values (use plus nonuse values) for aquatic resource improvements under 316(b) regulatory options. EPA decided not to employ the survey results for purposes of decision-making and EPA has not accounted for values estimated from the survey in the quantitative comparison of costs and benefits. It is also important to note that EPA's stated preference survey was designed to estimate respondents' willingness to pay for changes in the health of fish populations and aquatic ecosystems and to be statistically representative at large (regional and national) scales; the results were not specifically designed to be statistically representative at the facility level for the assessment of benefits for individual site-level permitting decisions.

As noted at the outset, it is not always the case that private decision making regarding withdrawals of cooling water takes into account society's preferences for fish protection, nor are there market transaction opportunities for individuals to express their willing to pay for fish protection. Thus, despite the limited information on monetized social benefits, EPA has concluded that the benefits of today's rule justify the costs of today's rule.

2. Comparison of the Other Options

As discussed above, EPA considered three other primary options before selecting today's rule. See Section VI.F Other Options Considered for more detailed explanation of each option. Exhibit VI–1 illustrates a comparison of the total annualized social costs and benefits.

EXHIBIT VI–1—COMPARISON OF THE PRIMARY OPTIONS FOR 316(b)

[$2011 Millions at 2013, 3% discount rate]

Option	Total annualized social cost	Monetized benefits
Proposal Option 4	$251.8	$31.0
Final Rule	274.9	32.8
Proposal Option 2	3643.2	−1542.6

I. Site-Specific Consideration of Entrainment Controls

As described above, EPA is not promulgating uniform national requirements for entrainment for existing facilities. Instead, EPA is setting standards for entrainment that include a framework by which a facility will be subject to a site-specific determination by EPA or a State NPDES permitting authority of appropriate BTA requirements for entrainment. This section describes the process for determining section 316(b) requirements for an individual facility under the national BTA standard for entrainment. It describes the elements that the Director must consider in the permitting decision and how costs and benefits may be considered in such an evaluation.

1. Implementation of a Site-Specific Evaluation of Entrainment for Existing Facilities

The final rule requires a site-specific determination of BTA entrainment conditions in individual permits and prescribes the requirements for that permitting proceeding. The final rule includes permit application requirements for facilities with a cooling water intake structure. These requirements are designed to elicit the information the Director needs to determine the best technology for reducing entrainment for a particular facility, including information pertinent to an assessment of whether the benefits justify the costs of any particular control measures under consideration.

Today's final rule is a modification of the proposed approach of a site-specific BTA entrainment determination. It will result in one of two outcomes at any facility:

1. Determination that the facility must install additional control measures that reduce entrainment beyond that achieved by the currently installed equipment. These may include closed-cycle cooling and/or other technologies.

2. Determination that the facility's current, existing technology for entrainment achieves the entrainment BTA requirements under the national BTA standard.

Thus, EPA expects that, under this approach, there will be additional entrainment controls for some facilities and none for others. Even where the Director's determination requires no additional control measures, the Director may conclude the permit should include conditions that specify proper operation and maintenance of the installed technology.

EPA notes that in a number of areas of the country (California, Delaware, New York, and New England; see, for example, DCNs 10–6963 and 10–6841, and EPA Region I's Brayton Point), permitting authorities have already required or are considering requiring existing facilities to install or retrofit to closed-cycle cooling systems. These facilities are still subject to today's rule but the existing requirements have been taken into account in costing.

For facilities that withdraw more than 125 mgd, the rule generally requires that the facility conduct an entrainment study as part of its permit application. The study will indicate, at a minimum, the specific entrainment data collection methods, taxonomic identification to the lowest taxon possible, latent mortality identification, documentation of all methods, and quality assurance/quality control procedures for sampling and data analysis appropriate for a quantitative survey. Peer reviewers must be selected in consultation with the Director, who may consult with EPA and Federal, State, and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure. Data from the entrainment study is important to provide corroboration of any through-facility entrainment survival study results in § 122.21(r)(7) or from any other studies conducted.

The final rule also requires the permit application to include the following information as part of the entrainment study (which refers to the requirements at § 122.21(r)(9) through (13), as opposed to the Entrainment Characterization Study at § 122.21(r)(9)). For a thorough discussion of these study requirements, see Section VIII:

- An engineering study of the technical feasibility and estimated costs of all candidate entrainment control technologies, including closed-cycle cooling, fine-mesh screens with a mesh size of 2 mm or smaller, and water reuse or alternative sources;
- A discussion of any outages, downtime, or other effects on revenue

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along with a discussion of all reasonable attempts to mitigate these cost factors

- A discussion of the magnitude of water quality benefits, whether qualitative, quantitative or monetized, of the candidate entrainment reduction technologies evaluated; thermal discharges; and
- A discussion of the changes in non-water quality environmental impacts and other factors attributed to technologies and/or operational measures considered, including, for example, increases and decreases in the following: Energy consumption; air pollutant emissions including particulates and their health and environmental impacts; noise; safety (e.g., visibility of cooling tower plumes, icing); electric grid reliability, and facility reliability.

The permit application will provide the Director with information about options for entrainment reductions at the site and other possible avenues for addressing any adverse effects from entrainment. The purpose of the entrainment study and other permit application materials is to assist the Director in better understanding the effect of entrainment on species in the waterbody from which cooling water is withdrawn. More specifically, the entrainment study will identify species that might be entrained, and estimate their baseline entrainment rates given current entrainment controls. Moreover, the entrainment study will include information about the aquatic ecosystem effects of entrainment of species, and any threatened and endangered species whose range of habitat includes waters where the facility's intake is located. An understanding of the potential ecosystem consequences of entrainment for species will help inform Director decisions about additional information required in the permit application, or permit requirements for any possible additional technologies and management practices. EPA will endeavor to identify high-quality examples of entrainment studies as they are completed, and post them to its Web site for this rule as a resource for study preparation.

EPA's benefits estimates were based on an extrapolation of available literature on impingement and entrainment studies; the specific Entrainment Characterization Study prepared by a facility could lead to a different estimate of impingement and entrainment for that facility relative to its share of EPA's estimate in the analysis supporting this rule and in the record.

Following the Director's review of this information, the Director must determine what BTA entrainment requirement to propose and explain in writing the basis for the draft permit. The draft permit will then be available for comment from the interested public under the Director's normal permitting process.

2. Site-Specific Consideration of Cost and Benefits

In establishing requirements under section 316(b) of the CWA, the Supreme Court in *Entergy* made clear that one factor that EPA may, but is not required, to consider is the costs and benefits associated with various control options. That is, in setting standards, EPA may consider the benefits derived from reductions in the adverse environmental impacts associated with cooling water intake structures and the costs of achieving the reductions. As previously explained, following E.O. 13563, EPA has determined that the benefits of the final rule justify its costs. In addition, EPA has explained (in Section II.C above) why consideration of quantitative and qualitative social costs and benefits may be appropriate in the site-specific determinations when establishing entrainment controls.

In the site-specific proceeding, the Director must consider, among other factors, monetized, quantified and qualitative social benefits and social costs of available entrainment controls, including ecological benefits and benefits to any threatened or endangered species. The Director may be able to reject otherwise available entrainment controls if the costs of the controls are not justified by their associated benefits (taking into account monetized, quantified, and qualitative benefits), and the other factors discussed in the final rule.

In making the site-specific entrainment BTA requirements determination, the final rule requires that the Director consider the information submitted under § 122.21(r) with the section 316(b) permit application. Further, in the case of the larger withdrawing cooling water intake structures (125 mgd AIF or greater), the rule requires submission of additional information including, studies on entrainment at the facility, the costs and feasibility of control options, and information on the benefits of entrainment controls. In evaluating benefits, the Director should not ignore benefits that cannot be monetized or quantified or consider only the impingement and entrainment reductions that can be counted. To result in appropriate decisions from society's standpoint, the assessment of benefits must take into account all benefits, including categories such as recreational, commercial, and other use benefits; benefits associated with reduced thermal discharges; reduced losses to threatened and endangered species; altered food webs; benefits accruing nonlocally due to migration of fish; nutrient cycling effects; and other nonuse benefits. Merely because it is difficult to put a price tag on those benefits does not mean that they are not valuable and should not be included at least qualitatively in any assessment. The rule does not require the Director to require a facility owner or operator to conduct or submit a willingness-to-pay survey to assess benefits. Further, the rule does not limit the Director's discretion to consider non-water quality impacts in determining whether further entrainment measures are justified. When some benefits are not monetized, the requirement to consider costs and benefits in today's rule does not mean the Director should base decisions solely on the monetized benefits and costs, ignoring the non-monetized benefits. Instead, the Director should consider the costs and what the magnitude of the non-monetized benefits would have to be in order to justify the costs.

An aggregate evaluation of benefits (even if accurate) would not account for the variations in benefits from location to location. On the basis of available information, EPA's analysis of benefits relied on extrapolating data from existing impingement and entrainment characterization studies to all facilities in the same region on a flow-weighted basis. Differences in species, life stages, and biological abundance across intake locations (even within a region) could lead to very different results for a site-specific analysis of a facility as compared to that facility's share of national costs and benefits, even if the national results are, on average, accurate. A national assessment tends to mask variations in benefits and costs from different geographical locations for different water bodies. For example:

- Some fish species at coastal facilities have biological spawning attributes that differ from those at other locations.
- The proportion of the receiving water withdrawn for cooling could also vary among sites.
- The values that communities place on their resources could vary from site to site.
- One ecological environment might experience large masses of hardier eggs and larvae subject to potential entrainment; another will have fewer but less hardy eggs and larvae susceptible to entrainment. Without

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detailed study information, it's difficult to ascertain which ecological environment faces the greater adverse environmental impact from a similar cooling water intake.

The resulting differences in the value of reduced entrainment—which could be dramatic for some sites—necessarily disappear in a national aggregation of results. The Agency has decided that this masking of variation in benefits further supports EPA's decision to require consideration of the site-specific benefits of entrainment control technologies in the site-specific process to establish entrainment controls.

The Director must then explain the basis for rejecting an available technology not selected for entrainment control in light of the submissions after consideration of the three factors that supported EPA's determination not to establish a uniform national entrainment standard based on closed-cycle cooling. The Director also must base the determination about BTA controls on the number and types of organisms entrained, including Federally-listed, threatened and endangered species and designated critical habitat (e.g., prey base) as well as consideration of the site-specific social costs and benefits (monetized and nonmonetized) of the various control technologies considered for the facilities.

As noted, the Director may reject an otherwise available entrainment technology as the BTA requirement (or not require any additional BTA controls) if the social costs of the controls are not justified by the social benefits (monetized and nonmonetized). EPA decided to adopt this approach in determining site-specific entrainment controls because it is permissible under *Entergy,* under E.O. 13563, and consistent with the more than 30-year history of section 316(b) permitting decisions.

This history illustrates the role that cost/benefit considerations have played. As early as 1977, EPA in a permitting decision and a General Counsel opinion explained that, while section 316(b) does not require a formal cost-benefit analysis, the relationship of costs and benefits may be considered in 316(b) decision making. *In re Pub. Serv. Co. of N.H. (Seabrook Station, Units 1 and 2),* No. 76–7, 1977 WL 22370 (June 10, 1977), remanded on other grounds, 572 F.2d 872 (1st Cir. 1978); accord *In re Central Hudson Gas & Elec. Corp., Op. EPA Gen. Counsel,* NPDES No. 63, 1977 WL 28250, at *8 (July 29, 1977). In the more than 30 years since, EPA and State permitting authorities have considered the relationship between costs and benefits to some extent in making individual permitting decisions. See, for example, *In re Pub. Serv. Co. of N.H. (Seabrook Station, Units 1 and 2),* No. 76–7, 1978 WL 21140 (E.P.A. Aug. 4, 1978), aff'd, *Seacoast Anti-Pollution League* v. *Costle,* 597 F.3d 306, 311 (1st Cir. 1979).

Because E.O. 13563 directs agencies to propose and adopt rules only upon a reasoned determination that the benefits justify the costs, EPA is allowing this consideration to be applied at the permit level. This approach is consistent with the historical application of section 316(b) requirements and will allow for a full assessment in permit decisions of both qualitative and quantitative benefits and costs. As designed, EPA's requirement for the establishment of site-specific BTA entrainment requirements strikes an appropriate balance between environmental improvements and costs, allowing the Director to consider all the relevant factors on a site-specific basis and determine BTA on the basis of those factors.

After considering the factors relevant to a site, the Director must establish appropriate entrainment controls at those facilities. The Director must review available control technology and may reject otherwise available entrainment controls as BTA if the social costs of the controls are not justified by their social benefits (taking into account both quantified and non-quantified benefits) or if the Director concludes that there are other unacceptably adverse factors that cannot be mitigated. As designed, EPA's national BTA standard for establishing site-specific BTA entrainment requirements strikes an appropriate balance between environmental improvements and costs by selectively requiring closed-cycle cooling or other entrainment technologies at some facilities, without requiring the same technologies at all facilities.

3. Potential Cost for Site-Specific Entrainment Controls

For the proposed rule, EPA analyzed possible additional costs associated with reductions in entrainment mortality that might result from the Directors' determinations of site-specific BTA requirements. Because this process will play out over a number of years as Directors consider waterbody-specific data, local impacts, and public comment, and weigh land availability, air quality impacts, and remaining useful life, those estimates of the costs of site-specific determinations are highly speculative. EPA is not presenting specific cost estimates today for prospective entrainment requirements because we do not have in hand the robust data that will be generated for individual site-specific settings as required under the national BTA standard for entrainment. Without that refined information on a site-specific basis, EPA has no ability to predict Director decision-making and therefore, the Agency is not estimating costs associated with the ultimate entrainment requirements. Similarly and for the same reasons, EPA did not estimate costs associated with requirements at §§ 125.94(g), 125.94(c)(8) or 125.94(c)(9).

EPA estimates that the most effective technology for reducing entrainment, closed-cycle cooling, is not available to at least one quarter of all facilities because of geographic constraints, air permitting restrictions in a nonattainment area and remaining useful life of the facility. EPA has limited information on which facilities these are, despite the certainty that these availability concerns are real and significant. In addition, EPA does not have in hand the site-specific data that will be generated as a result of today's rule. If EPA had this data, it would be possible to estimate the costs and benefits ultimately associated with the Directors' site-specific determinations under the national BTA standard for entrainment. The hypothetical costs generated at proposal were reported in an attempt to signal that EPA neither expects that zero facilities would be subject to closed-cycle cooling as a result of the site-specific BTA process for entrainment, nor that all facilities at which these technologies are feasible would be subject to closed-cycle cooling requirements. Without the site-specific information, there is significant uncertainty around any estimates EPA could generate of these costs (including those reported at proposal) and benefits.

VII. Response to Major Comments on the Proposed Rule and Notices of Data Availability (NODAs)

Over 1,100 organizations and individuals submitted comments on a range of issues in the proposed rule, including over an additional 62,000 letters from individuals associated with mass letter writing campaigns. An additional nearly 250 comments were received on the two NODAs. Responses to all comments, including those summarized here, are in the Response to Comments document in the official public docket (see DCN 12–0004). To facilitate a more comprehensive response and to simplify the task of discussing EPA's rationale for promulgating the final rule, EPA is

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responding to these public comments in essay form. Each topic area discussed in the comment letters has been addressed in one of the comprehensive essay responses. The major comments received and EPA's responses are summarized in this section.

A. Scope and Applicability

1. Source of Water—Impoundments

Many commenters expressed concern that the proposed rules do not adequately address the unique water bodies resulting from the many man-made reservoirs specifically designed and constructed as cooling water impoundments (referred to as cooling ponds in the proposed rule). Commenters expressed confusion regarding the applicability of the proposed regulations because impoundments have both intakes from the impoundments and intakes that supply water to the impoundment. Many requested that EPA clarify that man-made impoundments, built to supply water for power plants, do not constitute water of the United States for purposes of implementing the rule or that they should be classified as meeting the definition of closed-cycle cooling.

Response: As discussed in Section I, facilities that withdraw cooling water from impoundments that are waters of the United States and that otherwise meet the criteria for coverage (including the requirement that the facility has or will be required to obtain an NPDES permit) are subject to today's rule. Revisions to the definition of waters of the U.S. are outside the scope of this rulemaking. However, today's regulatory definition of closed-cycle recirculating systems specifies that such a system may include impoundments of waters of the U.S. where the impoundment was constructed prior to today's final rule. To meet the rule definition for closed-cycle recirculating system, this impoundment must have been lawfully created for the purpose of serving as part of the cooling water system as documented in the project purpose statement for the Clean Water Act section 404 permit obtained to construct the impoundment. In the case of an impoundment whose construction pre-dates the CWA requirement to obtain a section 404 permit, EPA expects documentation of the project's purpose to be demonstrated to the satisfaction of the Director. This documentation could be some other license or permit obtained to lawfully construct the impoundment for the purposes of a cooling water system, or other such evidence as the Director finds necessary.

The definition of closed-cycle recirculating system at § 125.92(c)(1) of today's rule also specifies that impoundments that are not waters of the United States but withdraw make-up water from waters of the U.S. meet the definition of a closed-cycle recirculating system, if make-up withdrawals have been minimized. These impoundments are constructed in uplands, and are not required to obtain a 404 permit. Thus, these impoundments do not need to provide documentation of the project's purpose.

2. New Units

In the proposal, EPA defined new units as newly built units added to increase capacity at the facility. The definition did not include any rebuilt, repowered or replacement unit, including any units where the generation capacity of the new unit is equal to or greater than the unit it replaces. Many industry stakeholders agreed that the definition of new units should not include repowered existing units. Others thought that new units should be treated similarly to existing units with entrainment standards applied on a site-specific basis and that the nine proposed factors should also be applied to entrainment decisions for new units. Environmental organizations argued that EPA should set a deadline by which all existing facilities must comply with the new unit standards and that EPA's exclusion of repowered/rebuilt facilities created a loophole through which existing facilities could perpetually operate as an existing unit, even after replacing all of the generating equipment. Many of the comments had several elements in common:

- Requirements should be flexible enough to address sites where meeting the requirements is not technically feasible (e.g., limited land availability).
- EPA needs to provide greater clarity regarding how new unit standards apply to manufacturing facilities.
- The DIF is a more appropriate parameter for determining compliance because AIF cannot be determined until after the system is built, and baseline AIF would require assumptions about as-yet undetermined operational factors.
- It is unclear how the new unit requirements will be applied to manufacturing units, and the requirements do not appear to consider the circumstance where a new unit is constructed at an existing manufacturing facility where construction of the new unit does not require any modifications to the existing intake structure.
- Some commenters have noted that the new unit provisions are a departure from previous determinations and are unclear. They argue that they have not had adequate opportunity to comment on this issue and request EPA re-propose new unit requirements if it wants to continue with this initiative.

Response: EPA's definition of a ''new unit'' for the final rule can be found at § 125.92(u). New units includes the addition of a stand-alone unit that is constructed at an existing facility. The rule definition makes it clear that the new unit may be for the same general industrial activity as the existing facility. Because the requirements are much like the Phase I requirements for new facilities the costs for installing controls at new units are similar to the costs imposed on new facilities. The cooling water withdraws made by the rest of the existing facility are subject to the requirements at 40 CFR 125.94(c) and (d).

With respect to impingement mortality and entrainment, the final rule requires, at § 125.94(e)(1), that new units achieve flows commensurate with that of a closed-cycle recirculating system. As with the new facility Phase I rule, the new unit may choose to meet an alternative requirement at 40 CFR 125.94(e)(2) and demonstrate to the Director that the technologies and operational measures employed will reduce the level of adverse environmental impact from any cooling water intake structure used to supply cooling water to the new unit to a comparable level to that which would be achieved upon implementing closed-cycle recirculating for that new unit. This includes a demonstration showing that the entrainment reduction is equivalent to 90 percent or greater of the reduction that could be achieved through implementing a closed-cycle recirculating system. This demonstration must also include a showing that the impacts to fish and shellfish, including important forage and predator species, within the watershed will be comparable to those which would result if the facility were to implement a closed-cycle recirculating system.

Facilities may choose to install a closed-cycle recirculating system, and EPA has observed that many new units are selecting closed-cycle recirculating systems on their own, particularly for combined cycle and natural gas for reasons unrelated to 316(b) (such as water availability). In these cases, benefits related to reductions in IM&E would be expected to occur.

Finally, for new units at existing facilities, the Director may establish alternative requirements if the data specific to the facility indicate that

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compliance with the requirements of paragraphs (e)(1) or (2) of § 125.94 for each new unit would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at issue, or would result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on local energy markets. This provision is identical to that provided in the Phase I new facility rule.

B. Proposed Amendments Related to Phase I Rule

Commenters suggested that restoration be allowed in a range of situations, including where a nuisance species is a problem that will get worse with the use of cooling water intake structure technology, where affected species are not species of concern in man-made lakes, and to reduce the cost of meeting 316(b) requirements (i.e., offset losses).

Response: The Second Circuit found that EPA exceeded its authority by allowing facilities subject to CWA section 316(b) to comply with section 316(b) through restoration measures and, thus, EPA has deleted these provisions from the regulations at §§ 125.84 and 125.86 to make the rule consistent with the court decisions.

C. Environmental Impact Associated With Cooling Water Intake Structures

Many commenters expressed concern that limited scientific evidence exists that measureable aquatic population or community effects occur as a result of cooling water withdrawals and that impingement mortality and entrainment mortality requirements should not apply unless adverse environmental impacts are demonstrated. They also noted that not all environmental impacts are adverse. For example, removal of invasive species or quickly reproducing species might not be harmful.

Response: EPA disagrees. The evidence shows that the total number of aquatic organisms lost annually is in the hundreds of billions, or is 1.9 billion on an age-one equivalent basis. Additional data provided in comments shows aquatic organisms are lost through impingement and entrainment by all types of cooling water intake structures. The data demonstrates that the effects of cooling water intake structures on the aquatic environment are significant and widespread. In addition, there is documented evidence of population level effects of cooling water intakes for certain species in certain instances. See, for example, 69 FR 41587, July 9, 2004 for a discussion from the 2004 Phase II rule. Also, Bayshore, Indian River and Indian Point are discussed in the BA for the final rule.

D. EPA's Approach to BTA

1. Relationship of Costs and Benefits

Many commenters expressed concern that the proposed rule's costs significantly outweigh the benefits and that studies, technology modifications, monitoring, and reporting should not be required if costs exceed benefits.

Response: While the rule costs exceed the monetized benefits as presented, EPA has concluded that the costs do not outweigh total benefits when both monetized and nonmonetized benefits are considered. EPA notes that the monetized benefits are only a subset of all benefits. In the absence of complete estimates of nonuse benefits, EPA estimated partial nonuse benefits for the final rule using the benefits transfer approach from proposal. This approach is still a partial estimate, because the nonuse benefits transfer was based on a species that represents less than one percent of adverse environmental impacts. With respect to entrainment, the rule authorizes the Director to consider costs versus benefits on a site-specific basis. With respect to impingement mortality, the rule provides seven compliance alternatives based on a set of widely used, demonstrated, proven technologies, many of which have been in use for decades and whose efficacy is well supported in EPA's record.

2. Site-Specific Approach

Many commenters agreed with EPA's site-specific approach for entrainment mortality requirements but argued that the same approach should also be applied to impingement mortality requirements. State agencies and environment organizations are concerned that the site-specific entrainment determinations will create additional administrative burdens on already overextended permitting authorities which could exacerbate permit backlogs.

Response: EPA does not agree that impingement mortality is best addressed by the same approach adopted for entrainment. This is because EPA has been able to identify low-cost technologies that are available, feasible and demonstrated for impingement mortality nationally. EPA has not been able to identify an available, feasible and demonstrated technology nationally for entrainment, and therefore has adopted as its national BTA entrainment standard a structured process for determining on a site-specific basis what entrainment controls are the best technology available at a particular facility. EPA agrees that site-specific entrainment has potential to create additional burdens for states, but EPA has tried to limit this burden by simplifying its information collection requirements from those at proposal. EPA has streamlined the information collection requirements so that information necessary for the Director to make a BTA determination is submitted by the permittee in the permit application early in the process, thus minimizing the number of transactions between permittee and the Director.

E. BTA Performance Standards

1. Impingement Standards

EPA received a substantial number of comments on how the final rule should address impingement mortality. EPA proposed an impingement mortality standard based on the performance of modified traveling screens with fish handling and return that required achievement of a numeric IM performance standard. As an alternative EPA proposed that a facility could demonstrate that either the design intake velocity or the actual intake velocity at its operation was less than 0.5 fps. Most of the commenters, including members of the U.S. Congress, state and local elected officials, and industry stakeholders, requested additional flexibility in complying with the impingement mortality standards. While the proposal would not specifically require the use of modified traveling screens with a fish handling and return system to meet the impingement mortality standards, some commenters interpreted the proposed rule as requiring this. EPA proposed impingement mortality standards that were expressed as a monthly average and a 12-month average. EPA recognizes, however, that some regulated entities might find a technology-based compliance option, rather than a performance-based approach, more attractive. Such an approach, particularly the specification of pre-approved technologies, could offer higher regulatory certainty, easier demonstration of compliance, and might offer a less expensive alternative because of reduced monitoring requirements associated with pre-approved technologies. Some commenters viewed the proposed impingement mortality standard as overly stringent and requested that EPA establish alternative impingement mortality standards, including site-specific impingement mortality

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requirements similar to those proposed for entrainment. Other commenters provided data pertaining to the performance of technologies, including modified traveling screens used as the basis for the impingement mortality performance standard. Several industry stakeholders stated that, despite EPA's best intentions, the proposed rule applied a one-size-fits-all approach for impingement mortality. While all the suggested changes to the proposal seek to provide additional flexibility through a variety of approaches, most of the comments had several elements in common:

- Defining modified traveling screens as a pre-approved technology or otherwise streamlining the NPDES process for facilities using the candidate technology on which BTA is based. Thus, EPA would designate certain technologies or certain conditions as complying with the impingement requirement.
- Providing a mechanism to identify other technologies that perform comparably to modified traveling screens.
- Modifying the proposal so that facilities that have already reduced the rate of impingement could obtain credit toward the impingement mortality standard.
- Developing a more tailored approach to protecting shellfish.
- Creating alternatives for facilities with very low (de minimis) impingement levels or mortality rates.
- Providing additional clarity on species of concern as it pertains to demonstrating compliance with the numeric impingement mortality performance standard.
- Reevaluating the impingement mortality numerical performance standards.

In addition, as noted above, EPA also received a number of comments suggesting that it adopt a site-specific approach to reducing impingement mortality similar to the proposed approach for addressing entrainment, rather than uniform national requirements for impingement mortality and a site-specific approach for entrainment only.

Many commenters expressed concern that the entrapment requirements were not well defined and would require costly technologies that are not considered in EPA's cost estimates and could be difficult to comply with, particularly where cooling systems employ impoundments or basins downstream of the initial intake structure.

Response: See the earlier discussion concerning how EPA determined the numeric impingement mortality performance standard. Additionally, see earlier discussion for an explanation of how EPA revised the impingement mortality standard to provide seven alternatives for compliance.

EPA agrees that specific entrapment requirements are not necessary and requirements for facilities to deploy technologies to avoid entrapment have been deleted from the final rule. However, a facility that entraps fish must count the entrapped organisms as impingement mortality.

2. Entrainment Standards

A substantial number of commenters supported EPA's site-specific approach for entrainment standards. Suggested revisions to the approach included the following:

- EPA should recognize the value of waterbody-based requirements, including withdrawals on lakes/reservoirs and less than 5 percent of rivers as not requiring entrainment mortality.
- Units with a low capacity utilization should be exempt from entrainment mortality.
- Facilities with AIF of less than 125 mgd should be presumed as entrainment mortality compliant.
- EPA should consider entrainment survival.

Response: With respect to waterbody-based requirements and capacity utilization thresholds, EPA disagrees with commenters suggestions. There is no fundamental difference in technological performance based on waterbody so there is no need to subcategorize based on waterbody. EPA found that low CUR facilities are generally peaking plants that operate at full capacity for portions of days during a few months or less. Further, EPA found that some sites continue to withdraw water through their cooling water intake structure even when no power is being generated. If that period of cooling water intake operation corresponds with times when spawning is occurring, those facilities could have significant impacts from impingement and entrainment. Therefore, simply being a low CUR unit does not imply no adverse environmental impacts. Instead, EPA found that low CUR should be looked at more closely on an individual unit basis. EPA has included a provision in the final rule that states where a generating unit has an annual average capacity utilization rate of less than 8 percent averaged over a 24-month block contiguous period, the owner or operator may request that the Director establish less stringent standards for IM. With respect to facilities below 125 AIF being considered entrainment compliant, EPA disagrees with the comment since any facility at any flow may have an adverse environmental impact. With regard to entrainment survival, EPA does allow for consideration of entrainment survival. The monitoring requirements for entrainment for new units at § 125.96(d)(3) states that mortality after passing the cooling water intake structure must be counted as 100 percent mortality unless you have demonstrated to the approval of the Director that the mortality for each species is less than 100 percent.

3. Closed-Cycle Cooling

Both industrial stakeholders and many state agencies endorsed an approach that deems facilities with closed-cycle cooling to be in compliance with the BTA impingement mortality standard, and eligible for reduced monitoring and reporting requirements. Most industrial stakeholders agreed with the EPA decision that closed-cycle cooling should not be imposed as a national BTA standard. They argue that although closed-cycle cooling might be available and achievable at many facilities, requiring closed-cycle cooling nationally has numerous drawbacks including the following:

- Requirements for closed-cycle flow reduction do not take into consideration the site-specific limitations at some facilities (e.g., blowdown water quality, scale, fouling problems).
- Cooling towers would result in significant adverse impacts from fine particulates, carbon dioxide emissions, evaporative water loss, and other issues.

Commenters expressed concern that the proposed definition of a closed-cycle recirculating system is far more restrictive than the definition used in the Phase I rule. It includes only systems that withdraw make-up flow intermittently, are designed to operate above minimum COC, reduce flow by a specified percentage (depending on whether salt or fresh water), and did not include impoundments that are waters of the United States. Some commenters stated that while they might have been effectively operating as closed-cycle units for many years, they have concerns with their ability to comply with the definition in the proposal, particularly with respect to the specified COC.

Response: EPA agrees that facilities employing a closed-cycle recirculating system for entrainment should also be deemed in compliance with the impingement mortality standard, as long as the system is properly operated. While a closed-cycle recirculating

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system is the most effective technology for reducing entrainment, EPA has not established BTA based on closed-cycle cooling because EPA concluded it was not BTA, for the reasons specified in Section VI. Regarding the definition of closed-cycle cooling, EPA identified two parameters that demonstrate proper operation: Flow reduction and cycles of concentration. To provide flexibility, EPA has removed the numeric levels of the metrics as threshold, while retaining the minimized makeup flows aspect of the definition. Therefore while the definition in this final rule does not establish fixed requirements in terms of COC and comparable percentage flow reduction to qualify as a closed-cycle recirculating system, the rule provides that a closed-cycle recirculating system ''generally'' will achieve the specified benchmarks that characterize a properly operating closed-cycle cooling system. EPA further recognizes that certain unavoidable circumstances could exist where the specified COC or percent reduction values might not be achievable. Such site-specific circumstances could include situations where water quality-based discharge limits might limit the concentration of a pollutant that is not readily treatable in the cooling tower blowdown or situations where the source water quality could lead to unavoidable problems concerning scale formation, solids buildup, corrosion, or media fouling. If a facility can demonstrate that these occurrences are unavoidable, under the definition in the final rule, the Director may determine that such a facility is a closed-cycle recirculating system, taking into account the site-specific circumstances. In addition, EPA has explained how the conditions added to the existing facilities definition do not in effect make it more stringent than the Phase I definition of closed-cycle recirculating systems. The auxiliary electricity a facility uses to run the fans in a closed-cycle system is electricity the facility can't sell. The opportunity cost to the facility of using that electricity to run the fans is the forgone revenue they would have been able to earn if they had run their cooling water system in once-through mode. The forgone revenue provides the incentive for a facility to run its closed-cycle system in once-through mode, rather than in closed-cycle mode. Thus, EPA adjusted the definition of a closed-cycle recirculating system to be appropriate for retrofit situations.

F. Implementation

Many commenters expressed concern that the compliance timeline for impingement mortality and entrainment requirements should be synchronized to prevent a facility from having to install technology to comply with impingement mortality requirements and then later be required to install entrainment mortality technology.

Response: To address this concern, EPA revised the impingement mortality compliance requirements to provide that after issuance of a final permit establishing the entrainment requirements under § 125.94 (d), the owner or operator of an existing facility must comply with the impingement mortality standard in paragraph § 125.94(c) as soon as practicable. When the Director establishes a compliance schedule under § 125.94(d), the schedule must provide for compliance as soon as practicable. Thus, EPA has synchronized decision making about technology requirements, avoiding situations where investments in IM controls would later be rendered obsolete by entrainment control requirements.

G. Costs

1. Impingement Mortality Technology Costs

Commenters expressed concern about the approach for technology assignments used to estimate compliance with the impingement mortality standards and generally asserted that costs were underestimated. These concerns included the following:

- The EPA incorrectly assumed traveling screens were an available technology at most facilities.
- EPA underestimated the costs of modified traveling screens.
- EPA underestimated the difficulty and costs of installing fish returns.

Response: EPA disagrees that traveling screens are not an available technology at most facilities; survey data provided by industry shows that 93 percent of generators and 73 percent of manufacturers already have screens. EPA agrees that some facilities may not be able to readily upgrade their screens to modified traveling screens with fish return, but that the vast majority can.

EPA has updated the estimated costs of the rule to reflect the difficulty of installing fish return and adjusted the cost of modified traveling screens to reflect most recently available vendor data. Specifically, EPA reviewed the cost methodology and made a number of revisions including the following:

- EPA revised the technology assignment such that only those model intakes that have existing traveling screens are assigned modified traveling screen costs.
- EPA increased the estimated capital costs for modified traveling screens by 20 percent.
- EPA increased the estimated capital costs of fish returns and provided for an additional increase for facilities whose intakes would be difficult to install fish returns.

For further discussion, see Section IX and the TDD (Chapter 8).

2. Entrainment Mortality Technology Costs

Industrial stakeholder commenters argued that closed-cycle cooling costs are underestimated and the cost analysis fails to include any costs for entrainment requirements. Riverkeeper argued that the EPA closed-cycle costs are overestimated.

Response: For both the proposal and this final rule, EPA revised the methodology for estimating closed-cycle costs from what was used for Phase II and Phase III. EPA's revised methodology is based on the cost methodology provided by the Electric Power Research Institute (EPRI). EPRI based its cost methodology on over 50 actual and planned closed-cycle cooling system retrofits and EPA concluded that these cost estimates better reflect actual costs. EPRI has updated their closed-cycle cost methodology since EPA adoption of the earlier version and provided an estimate of closed-cycle costs for generators with a design flow above 50 mgd (See DCN 12–6807). A comparison between the EPRI estimates and comparable EPA estimates indicate that the EPA capital and downtime costs are somewhat lower than the EPRI estimates, while the EPA energy penalty costs are higher. (See DCN 12–6656.) While Riverkeeper cites actual costs from retrofit projects completed in 1998 and 2002 to support the argument that EPA's capital costs are overestimated, EPA has identified more recent closed-cycle retrofits where the capital costs were much higher than the EPA average, suggesting that the costs used by EPA in the final rule are representative of the range of costs that may occur nationwide. (See DCN 12–6656.) Thus EPA considers its closed-cycle costs to reasonably reflect actual costs.

EPA also received estimated costs for closed-cycle retrofits at small, medium, and large manufacturing cooling systems from the American Chemical Council (ACC). A comparison of these costs to comparable EPA estimates indicated that for larger systems the costs are mostly in agreement but that for smaller systems (e.g., 5,000 gpm), the EPA cost estimates are lower. EPA's acknowledges its methodology uses a linear approach and does not fully

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account for the increased costs associated with the diseconomies of scale at the lower end of the spectrum of system sizes.

Under EPA's selected option, compliance for entrainment reduction requirements is established on a site-specific basis. Because no particular result is prescribed under this approach, it is difficult to ascribe compliance costs for this aspect of the rule without the site-specific information that will be generated as a result of the national BTA standard for entrainment decision-making established by today's rule. For Proposal Options 2 and 3 where closed-cycle cooling would be required, EPA did estimate costs for closed-cycle cooling. EPA has not estimated what site-specific determinations will be made as part of the analysis.

H. Monitoring and Reporting

1. Velocity Monitoring

Many commenters explained that it would be difficult to directly measure through-screen velocity for screen technology and agreed with the suggestion in the NODA that EPA should allow for calculation of through-screen velocity. Also, many were concerned that a velocity limit based on minimum water levels would be difficult to comply with. Of concern are extreme conditions that are beyond the facility's control (e.g., low water due to drought).

Response: EPA agrees that direct measurement of intake velocity on a traveling screen may be problematic in some circumstances, and the final rule allows intakes to comply with the low velocity IM compliance alternatives by either calculation or direct measurement. Compliance will be demonstrated through monitoring and reporting of actual or calculated intake velocities. Short-term exceedances of the velocity may be permissible for brief periods, with Director approval, for purposes of maintaining the cooling water intake system, such as backwashing the screen face. EPA expects that facilities will employ appropriate design and operational measures to ensure that the maximum velocity is not exceeded during minimum ambient source water surface elevations, as can be anticipated through best professional judgment using hydrological data.

2. Impingement Mortality Monitoring

EPA received many comments concerning impingement mortality monitoring. Issues regarding impingement monitoring included the following:

- Many commenters expressed concern that the impingement mortality standard is unclear as to what species the impingement mortality requirements apply.
- Intakes with low impingement would have difficulty calculating impingement mortality.
- Monitoring requirements for impingement mortality are excessive, especially given the physical and biological challenges of appropriate sampling.
- Monitoring requirements should be eliminated for properly installed/operated pre-approved technologies.
- Impingement ''selects'' impaired organisms, resulting in bias.

Response: EPA has addressed concerns regarding monitoring in the final rule. For example, there is no biological compliance monitoring for pre-approved and streamlined compliance alternatives in § 125.94 (c)(1) through (6) of today's rule beyond that required for the permit application, and monitoring may be greatly reduced for other facilities. EPA recognizes that biological monitoring can be expensive, which factored into EPA significantly reducing those requirements. With respect to intakes with low impingement having difficulty calculating impingement mortality, facilities can demonstrate under § 125.94(c)(6) that the rate of impingement is reduced due to intake location or other technologies or factors. Further, under § 125.94(c)(11) a facility can demonstrate to the Director that there is a *de minimis* rate of impingement such that no additional controls are warranted.

3. Reporting Requirements

Comments concerning reporting requirements included the following:

- Commenters argue that permit application deadlines are unreasonable, especially given the limited number of consultants available and that EPA overestimates the number of facilities that have completed these studies.
- Peer review requirements are overly burdensome.
- Permit application requirements are burdensome and EPA should revise the proposed rules to remove, limit, or streamline the numbers and types of data, studies, and reports required. Permit application requirements should be reduced for smaller facilities with intake flow in the 2–125 mgd range.
- The proposed rule requires the § 122.21(r) permit application materials for each permit cycle, regardless of whether the facility has been modified. After the initial assessment of BTA in the first permit cycle under the new rule, the permittee should not be required to do additional studies and submit further documentation unless there is a significant change in the facility's cooling system.

Response: EPA notes that facilities have several flexibilities to address the first point, including: (1) If a permit is issued prior to July 14, 2018, the Director can delay submission requirements until such time that the facility can complete them and (2) in permit terms subsequent to the first permit issued under today's rule, the Director can waive some or all of the studies. With respect to peer review, EPA disagrees that peer review is overly burdensome. How to undertake a peer review is widely known, generally following a well-established process. EPA notes that peer review is a normal part of Agency activities, and that commenters generally favor the application of peer review to environmental data and analyses. With respect to the burden of the permit application process and subsequent permit cycles, EPA has reduced the permit application requirements for the final rule and streamlined biological data collection to two years of data collected as part of the permit application (with the exception of the few facilities expected to comply with the impingement mortality standard under the alternative at § 125.94(c)(7)). In addition, entrainment studies are not prescribed for facilities below 125 mgd, although the Director may require the facility to provide information beyond the basic permit application information. Also, the Director can waive study requirements in permit terms subsequent to the first permit issued under today's rule.

I. Endangered Species Act

Some commenters argued that it is inappropriate to automatically treat T&E species in a special category and provide for special consideration for them under the rule. These commenters asserted that EPA has no basis for incorporating ESA requirements into the rule and addressing ESA species under the NPDES program; they argued that the ESA operates independently. Other commenters argued that EPA has an obligation under the ESA to consult with the Services if cooling water intake structures are likely to affect threatened or endangered species.

Response: EPA has addressed T&E species and critical habitat in this rule to the extent necessary to ensure that this action is consistent with both the Endangered Species Act and CWA section 316(b). Section 7 of the Endangered Species Act states that

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''each Federal agency shall, in consultation with and with the assistance of [the services] insure that any action authorized, funded, or carried out by [the agency] . . . is not likely to jeopardize the continued existence of any threatened or endangered species or result in the destruction or adverse modification of [designated critical] habitat.'' Under CWA section 316(b), facilities subject to NPDES permitting that have cooling water intake structures are subject to BTA to minimize adverse environmental impacts. The final rule requires NPDES 316(b) permittees to identify all Federally-listed threatened and endangered species and/or designated critical habitat that are or may be present in the action area. The Director may reject an otherwise available technology as a basis for entrainment requirements if the Director determines there are unacceptable adverse impacts including impingement, entrainment, or other adverse effects to Federally-listed threatened or endangered species or designated critical habitat. EPA consulted with the Services under the ESA regarding this rule, and a summary of the requirements related to threatened or endangered species is discussed in Section VIII.K of this preamble.

VIII. Implementation

The following sections describe how the Agency expects the final rule requirements to be implemented. The requirements of today's final rule will be applied to facilities through NPDES permits issued by EPA or authorized States under CWA section 402. A facility may generally choose to demonstrate compliance with the final rule by demonstrating compliance for the entire facility, or by demonstrating compliance for each individual cooling water intake structure. For example, a facility with two intakes could demonstrate flow reduction commensurate with an existing closed-cycle recirculating system for the first intake, and demonstrate the intake velocity at the screen face is less than 0.5 feet per second at the second intake. Alternatively, the facility could demonstrate that each of the facility's intakes are designed with an intake velocity of less than 0.5 feet per second. For details about the scope and applicability of today's final rule, see Section I above.

Today's final rule (as described in Section IV above) establishes permit application requirements for existing facilities in §§ 122.21 and 125.95, monitoring requirements in § 125.96, and record-keeping and reporting requirements in § 125.97. All existing facilities subject to the final rule that withdraw from one or more cooling water intake structures with a facility-wide DIF of greater than 2 mgd are required to comply with the national BTA impingement mortality standard at § 125.94(c) and national BTA entrainment standard at § 125.94(d). New units at existing facilities are required to meet the national BTA impingement mortality and entrainment standards at § 125.94(e).

The final regulations also require the Director to review permit application materials submitted by each regulated facility, establish impingement mortality and entrainment requirements in accordance with this rule, and issue permits that include monitoring and record-keeping requirements (§ 125.98). The permit application requirements, monitoring, record-keeping, and reporting requirements for each of the compliance alternatives are detailed in the following sections.

A. When does the final rule become effective and how are the requirements sequenced in an orderly way?

This rule becomes effective on October 14, 2014. The requirements in this rule will then be implemented in NPDES permits as the permits are issued.

EPA has sought to address the information and studies required in the permit application associated with ongoing permitting proceedings and subsequent permitting after the first implementation of this rule in a permit. The EPA realizes that, in some cases, a facility may already be in the middle of a permit proceeding at the time of promulgation of this rule, or the Director may have already required much of the same information be submitted by the facility prior to promulgation of today's final rule. Therefore the rule includes several provisions that provide flexibility for the permit application requirements. First, in the case of any permit expiring after July 14, 2018, under § 125.95 the facility must submit permit application materials required in § 122.21(r) with its next NPDES permit renewal application. Second, in the case of any permit expiring prior to July 14, 2018, under § 125.95 a facility may request that the Director waive the submission date of the permit application requirements of § 122.21(r) based on a showing by the owner or operator of the facility that it could not develop the information for which such a waiver is requested by the time required for submission of the permit renewal application. If the Director then chose to allow a delay for the submittal of any of the information requirements of § 122.21(r), the Director would then determine the schedule for submission of any delayed requirements to be as soon as practicable. Third, in the case of permit proceedings begun prior to the effective date of today's rule, and issued prior to July 14, 2018, the Director should proceed. See §§ 125.95(a)(2) and 125.98(g). In such circumstances where permit proceedings have already begun prior to the effective date of the rule, these facilities will still need to submit the appropriate permit application materials found at § 122.21(r) permit applications during their next application. Additionally, while EPA expects that many facilities will already comply with § 125.94(c), in some cases the facility will need to choose one of the compliance alternatives for IM in their subsequent permit cycle.[83] In particular, EPA expects the facility would submit the information required in § 122.21(r), and the Director would make a determination of BTA for entrainment for that facility. Only after the Director has established site-specific BTA requirements for entrainment reduction will the facility have to select the compliance alternative on which it will rely to meet the IM requirements of today's rule. The Director may either amend the permit to include the IM requirements or include them in a subsequent permit if the Director determines the proposed controls are consistent with § 125.94(c). The Director would establish a schedule incorporating each of these sequential actions. In addition, the rule allows the Director the flexibility to grant a request for a waiver of permit application requirements in § 122.21(r)(6) in order to accommodate the circumstances described here. See §§ 122.21(r)(1)(i) and 125.95(a). Fourth, in permit applications subsequent to the first permit issued under § 125.94(a)(1) with all required information submitted under § 122.21(r), the Director may approve a request to reduce information required, if conditions at the facility and in the waterbody remain substantially unchanged since the previous application.[84] See § 125.95(c). In

[83] EPA's costs do not assume zero compliance costs for prior BTA determinations or permit proceedings; all facilities were assessed costs on the basis of technologies in place as described in Section IX.

[84] However, if conditions at the facility or in the waterbody have in fact changed substantially since the previous permit application, the Director will revisit data collection needs and possibly the BTA determination. The presence of any habitat designated as critical, or species listed as threatened or endangered after issuance of the current permit

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addition to all of these flexibilities, today's final rule gives advance notice to affected facilities about permit application materials and compliance schedules.

While the final rule has both reduced and streamlined the permit application requirements, the EPA has determined that for many facilities, it may take as long as 39 months to plan, collect, and compile the data and studies required to be submitted with the permit application (see Section C below for a more detailed discussion of each application element). The rule therefore specifies that July 14, 2018 reflects the date after which all permit application requirements must be submitted as specified at § 125.95. Specific permit requirements may not need a full 39 months for completion, therefore the Director may establish a schedule for submission of the required permit application elements. For example, planning for required sampling may take 6 months, inclusive of establishing a sampling team, developing sampling protocols, and acquiring necessary equipment. Source water sampling and characterization under § 122.21(r)(4) includes two years' worth of data. Therefore, the EPA expects a minimum of 30 months will be necessary for submission of § 122.21(r)(4), assuming the facility collects new data; this timeframe could be shorter if the facility chooses to use existing biological data. Facilities choosing to comply with the IM requirements through either § 125.94(c)(5) or (c)(6) must collect at least 2 years data upon which the facility would demonstrate that the modified traveling screens or the facility's systems of technology have been optimized to minimize impingement mortality. Therefore, the EPA expects a minimum of 30 months will be necessary for submission of § 122.21(r)(6), assuming the facility collects new data. Collection of entrainment characterization data and studies should occur in parallel with IM studies and sampling. Thus, after the initial 6 month planning period, facilities that do not already have recent entrainment characterization data will collect a minimum of 2 years entrainment data under § 122.21(r)(9). Facilities are expected to need an additional 9 months to assemble the entrainment data and studies as required by § 122.21(r)(9) through (12). Therefore, the EPA has concluded that as many as 39 months will be necessary for final submission of all requirements under § 122.21(r). This time frame will be adequate for facilities under 125 mgd AIF; facilities over 125 mgd AIF also need to have their 122.21(r)(10) to (12) studies peer reviewed. The EPA expects 3 months will be needed for completion of peer review requirements and generation of a final report. However, many of the facilities over 125 mgd AIF were subject to the Phase II rule before it was suspended (that is, all electric generators over 125 mgd AIF are also above 50 mgd DIF), and likely need less time for up front planning and/or data collection. Therefore, the EPA has concluded that as many as 39 months will be adequate for these facilities to meet all requirements under § 122.21(r). These time frames are consistent with the timeline EPA included in the proposed rule, and also matches the 3½ years previously provided in the Phase II rule for data collection and studies. EPA notes the submission of the studies required with the permit application should not be confused with the schedule for compliance with the BTA requirements, as discussed below.

EPA has also sought to sequence the impingement mortality controls so that a facility may select and implement these controls after the Director's determination of controls on entrainment. With respect to entrainment requirements, existing facilities withdrawing greater than 125 mgd AIF must submit permit application materials including the studies prescribed in today's final rule at § 122.21(r)(9) through (13) in order to help the Director determine what entrainment controls to require at the facility. Facilities at or below this threshold must submit any information requested by the Director. The Director will then review these materials and determine if further entrainment controls are necessary. Once the BTA requirements for entrainment have been established, the facility would finalize its chosen method for compliance with impingement mortality under § 125.94(c). It would then be appropriate for the Director to develop a schedule whereby the facility would proceed to design, construct, and implement its technologies for impingement mortality, for entrainment, or for both together should the same technology addresses both impacts. In this manner, the EPA has harmonized the schedules for meeting both impingement mortality requirements and entrainment requirements.

EPA further notes that approximately 2 percent of facilities have no controls in place for impingement or entrainment, or that a facility may choose to install modified traveling screens as part of its compliance response. In these circumstances, not only does EPA expect such decisions to be delayed until after the Director has determined the BTA requirements for entrainment, EPA acknowledges that the required optimization study of § 122.21(r)(6) cannot be completed until after the technology has been designed and constructed. EPA has provided the Director the flexibility to establish an appropriate schedule for submission of such studies under § 125.95(a)(2).

After the effective date of the regulation, when the first permit implementing the new regulatory requirements is issued, permitting authorities typically consider the need to allow facilities some period of time to come into compliance. Under today's final rule, facilities will have to comply with the impingement mortality and entrainment requirements as soon as practicable according to the schedule of requirements set by the Director. The concept of compliance schedules may be found in the generally applicable NPDES regulations at 40 CFR 122.47. Because section 316(b) has no statutory deadline for meeting the ''best available technology for minimizing adverse environmental impact'' standard, there is no statutory bar to use of a compliance schedule in appropriate circumstances. The EPA recognizes that it will take facilities time to upgrade existing technologies, and install new technologies, and that there are limits on the number of facilities that can be simultaneously offline to install control technology and still supply goods and services to orderly, functioning markets. It is appropriate for the Director to take this into account when establishing a deadline for compliance. Any such schedule would take into account factors provided in § 125.98(c), such as measures needed to maintain adequate energy reliability by an electric generating facility, or extenuating circumstances such as scheduled production outages at a manufacturing facility.

There may be overlap in the technologies used to comply with impingement mortality and entrainment standards, which could result in the facility needing more time to comply with the impingement mortality requirements. For example, if a facility plans to retrofit to wet cooling towers to reduce entrainment, the wet cooling towers technology will also comply with the impingement mortality

(whose range of habitat or designated critical habit includes waters where a facility intake is located) constitutes potential for a substantial change that must be addressed by the owner/operator in subsequent permit applications, unless the facility received an exemption pursuant to 16 U.S.C. 1536(o) or a permit pursuant to 16 U.S.C. 1539(a) or there is no reasonable expectation of take.

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standard under § 125.94(c)(1). As such, the Director would schedule compliance with the impingement mortality requirements to match the schedule for entrainment requirements. Further, EPA recognizes that in some cases, especially where additional entrainment control technologies are required, the facility could require a lengthy period of time to design, construct, and implement control technologies. Therefore, the rule authorizes the Director, at § 125.94(h), to establish interim BTA requirements in a facility's schedule of requirements, for impingement mortality, entrainment, or both, where necessary on a site-specific basis.

In contrast to the proposed rule, today's final rule does not include a requirement for compliance with the impingement mortality standards within eight years. EPA expects, however, that the final rule will generally result in compliance within a similar period of time. The combination of permit issuance, the Director's determination of BTA for entrainment, and the subsequent schedule of requirements for impingement mortality will result in some facilities, particularly those already in a permitting proceeding, or with controls similar to what the new permit requires, being in compliance within a very short time frame. Some facilities that are not now in a permitting proceeding may need as much as three and a half years to fully complete their studies and data collection, and depending on the types of control selected, may need additional time to design, construct, and implement their technologies. In some cases, the Director's determination for entrainment may result in a facility meeting both the impingement mortality and entrainment BTA requirements in fewer than eight years. All facilities will be required to follow their schedule as determined by the Director.

EPA notes that there is a three-year period after the effective date of this rule before Directors will be receiving permit applications containing the full set of application requirements in § 122.21(r). EPA is aware that currently many NPDES permits for facilities with a CWIS have been administratively continued. For these administratively continued permits, the Director should consider if any permits would need additional updated information to support the permit issuance decision. The Director may, under 40 CFR 122.21(g)(13), request additional information including any permit application requirements in § 122.21(r).

B. How does the final rule reduce biological monitoring requirements?

The EPA has streamlined the biological data and study requirements for both impingement mortality and entrainment into one comprehensive set of permit application requirements and provisions. The Source Water Baseline Biological Characterization Data, impingement technology performance optimization study, Entrainment Characterization Study, and where applicable, entrainment performance studies are all conducted within the same two year time frame prior to submission of an application for a permit. Further, as shown in Exhibit VIII–1, EPA's analysis indicates that more than 99 percent of existing facilities will choose an alternative for impingement mortality that does not require continual biological compliance monitoring. Thus any required biological data consists solely of that required to be collected to meet the permit application requirements. See Section F for further discussion.

EXHIBIT VIII–1—EPA'S PROJECTIONS OF HOW FACILITIES WILL CHOOSE TO COMPLY WITH THE IM REQUIREMENTS

IM compliance alternative	Intake count [a]	Percent of total intakes
Closed-cycle recirculating system [c]	307	18
Design velocity	362	21
Actual velocity	226	13
Existing offshore velocity cap [c]	10	1
Modified traveling screens	488	29
System of technologies	278	17
Impingement Mortality Performance Standard	12	0.7
De minimis	**[b]	**[b]
Total	1,682	100

[a] EPA's compliance costs for each facility are based on the sum of the facility's intake level compliance costs. Some facilities have more than one intake. See IX.B.2 for more information on the use of the survey data.

[b] EPA has not estimated which facilities will be determined to be "de minimis" under § 125.94(c)(11) by the Director. For purposes of this analysis, EPA has assumed no facilities fall under the "de minimis" provision.

[c] EPA is not projecting facilities will install closed-cycle recirculating systems or offshore velocity caps to comply with the IM requirements, rather these facilities already have these technologies installed.

By merging the data collection and studies into the permit application requirements, EPA expects approximately half of all affected facilities will be able to complete the initial permit application within a few months.[85] In the case of a facility that was not previously required to collect data and conduct studies, it may take up to 45 months lead time for a permit to be applied for, and additional time for the permit to be issued. Although the permit application times may be longer for the first permit cycle after this rule, this is a tradeoff for the flexible IM requirements.

Once the permit is issued, EPA anticipates very few, if any, facilities will be required to conduct ongoing biological compliance monitoring related to impingement controls; for more details, see Section F and Exhibit VIII–4. Instead, for each subsequent permit cycle each facility would either (1) demonstrate to the Director that facility operations and waterbody characteristics are substantially unchanged, or (2) update any biological characterization data. Anticipating that NPDES permits are renewed when they expire, the update to the facility's biological characterization and any corresponding biological performance evaluations would be conducted approximately every five years.

[85] For example, facilities that were subject to Phase II will have already collected most of the data and information as part of the Phase II rule issued February 16, 2004 and implemented up until suspension of that rule on July 9, 2007.

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C. What information will I be required to submit to the director when I apply for my NPDES permit?

Today's final rule establishes, at § 122.21(r), permit application requirements for all facilities subject to the requirements of § 125.94. Each permit application element at § 122.21(r) is described in more detail below. The final rule requires existing facilities to prepare and submit some of the same information as previously required for new facilities subject to subparts I or N (*i.e.,* Phase I new power plants and manufacturers or Phase III new offshore oil and gas facilities), namely the information at § 122.21(r)(2) through (4). In addition, the rule adds subparagraphs for existing facilities to the regulations at § 122.21(r)(4), as well as (r)(5) through (13) to include the information and study requirements specific to existing facilities.

In the case of a new unit constructed at an existing facility, EPA expects much of the information submitted by the facility in previous permit applications would still be current and relevant. Therefore, EPA has reduced the permit application requirements to those necessary to update the facility's previously submitted information under § 122.21(r)(2), (r)(3), (r)(4), (r)(5), (r)(6), (r)(7) and (r)(8). In other words, the new unit permit application is intended to describe the changes to these documents as a result of the addition of the new unit. In addition, the facility must submit information specific to the new unit's chosen compliance method at § 122.21(r)(14).

All existing facilities are required to complete and submit permit application studies to describe the source waterbody (§ 122.21(r)(2)), cooling water intake structures (§ 122.21(r)(3)), characterize the biological community in the vicinity of the cooling water intake structure (§ 122.21(r)(4)), cooling water system (§ 122.21(r)(5)), and operational status (§ 122.21(r)(8)). Facilities that already use a closed-cycle recirculating system must still submit this information in their permit application. The Director will need, for instance, the biological sampling data in § 122.21(r)(4) to serve as a record basis for their BTA determination in the permit. Furthermore, in Phase I, new facilities were required to be commensurate with closed-cycle, to meet the 0.5 fps velocity limit, and to collect two years' worth of biological data to establish a record basis for impacts at the facility. In addition, the data collected here is important to inform an owner/operator's evaluation of whether and if so what threatened or endangered species or designated critical habitat are or may be present in the action area.

All existing facilities must describe their existing impingement and entrainment technologies or operational measures and a summary of their performance, including but not limited to reductions in impingement mortality and entrainment due to intake location and reductions in total water withdrawals and usage (§ 122.21(r)(5)(iii)). All facilities must also complete and submit their chosen compliance method for impingement mortality (§ 122.21(r)(6)). This includes identification of any requests for BTA determinations under § 125.94(c)(11) *de minimis rates of impingement* or § 125.94(c)(12) *low capacity utilization power generation units.* In addition, the owner or operator of an existing facility must submit the information required under paragraph (r)(6) of § 122.21 for the alternative specified at 40 CFR 125.94(c) that the owner or operator of an existing facility chooses to rely on as its method of compliance with the BTA Standards for Impingement Mortality specified in 40 CFR 125.94. Because the IM compliance options § 125.94(c)(1), (2), and (4) include pre-approved technologies, the owner or operator of a facility choosing one of these three options to comply with the IM requirements does not have either biological studies or biological compliance monitoring related to the applicable IM standard. Compliance options § 125.94(c)(3), (5), and (6) are streamlined options. For two of these three options, the permit application element § 122.21(r)(6) further requires a site-specific study for the purposes of technology optimization to minimize impingement mortality, including additional biological data collection that in most cases would occur during the same two year period of data collection for the Source Water Baseline Biological Characterization Data required under § 122.21(r)(4) to characterize the baseline, and a demonstration that the operation of specific technologies at your facility have been optimized to minimize impingement mortality. The owner or operator of a facility choosing one of these three options to comply with the IM requirements do not have ongoing biological compliance monitoring as part of the applicable IM standard. As discussed in the previous section, the Director can establish a schedule [86] for submitting the optimization study if the facility first needs to install additional technology for IM.

All existing facilities may submit to the Director additional permit application studies to describe biological survival studies that address technology efficacy and other studies on entrainment at the facility (§ 122.21(r)(7)). This requirement does not impose any new or additional study requirements. This permit application element includes the submission of existing studies conducted by or relevant to the facility. Further, the burden of this requirement has been reduced since proposal by only referring to studies of entrainment.

All existing facilities that withdraw more than 125 mgd AIF [87] of water for cooling purposes must also submit additional information to characterize entrainment and assess the costs and benefits of installing various potential technological and operational controls. These facilities are required to submit to the Director additional permit application studies including § 122.21(r)(9), Entrainment Characterization Study; § 122.21(r)(10), Comprehensive Technical Feasibility and Cost Evaluation Study; § 122.21(r)(11), Benefits Valuation Study; and § 122.21(r)(12), Non-water Quality Environmental and Other Impacts Assessment. As with the biological data collection required of some facilities under § 122.21(r)(6), EPA expects biological data collection for the purposes of entrainment characterization to occur during the same two year period of biological data collection required under § 122.21(r)(4). EPA notes that facilities below the 125 mgd threshold are not automatically exempt from entrainment requirements. The Director may determine that entrainment studies may be required or that entrainment controls may need to be installed for any cooling water intake structure. See the Section VI of this preamble for more information.

The final rule further requires the studies at § 122.21(r)(10) through (r)(12) be subject to an external peer review as required at § 122.21(r)(13); a separate peer review is not required for § 122.21(r)(9), as it is implicitly

[86] The Director could, for example, issue a permit before the optimization study has been completed, and include a schedule for submission of the optimization study in the newly issued permit.

[87] AIF is calculated from the most recent three years' data or five years in subsequent permit cycles. As such, AIF is a variable number. It is possible that a facility could transition from below 125 mgd to above 125 mgd if the facility significantly increases withdrawal of cooling water, such as if the facility increases capacity or if it adds a new unit. In these cases, the facility will then be required to conduct the studies and meet the permit application requirements at § 122.21(r)(9)–(13). This consequence is intended to incentivize facilities to reduce or reuse water for cooling, thereby avoiding the need for additional permit application studies.

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reviewed via its use in § 122.21(r)(10) and (r)(11). EPA expects the facility would first notify the Director of the peer review in advance. For example, facilities could identify their peer reviewers near the beginning of their biological data collection for the required Entrainment Characterization Study at § 122.21(r)(9). Since a facility's permit application requires two years of biological data, EPA expects this is more than enough time for the facility to identify peer reviewers, and for the Director to disapprove of a peer reviewer or require additional reviewers. Further, this provides the Director ample opportunity to confer with those agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure, including other Federal, State, and Tribal agencies. Similarly, in the case of permits for electric generating utilities, EPA expects this is enough time to confer with state co-regulators such as public utility commissions, or independent system operators whose responsibility it is to ensure reliability of the electricity grid. To minimize the overall time required to conduct a peer review, all studies conducted by the facility under § 122.21(r)(10) through (12) will be subject to peer review at the same time, in a holistic fashion. Additional guidance on conducting peer review is available on EPA's Peer Review Program Web site at *www.epa.gov/peerreview*. EPA expects the Director will use the permit application information, studies, and peer review results to assess the impingement and entrainment impacts of the cooling water intake structure and determine appropriate technological or operational controls, or both, as necessary.

While all facilities must submit § 122.21(r)(2) through (6) and (r)(8) and, where applicable (r)(7), EPA has reduced the permit application requirements based on the facility's chosen compliance method for impingement mortality. Exhibits VIII–2 and VIII–3 below illustrate the permit application requirements as they relate to an existing facility's chosen compliance methods. EPA expects permit application requirements for new units will consist of updates to previously submitted permit applications for the rest of the existing facility at which the new unit is being constructed.

For a new unit at an existing facility, EPA expects that only the appropriate and relevant updates to the existing facility's permit application materials are required (in addition to newly developed materials required at § 122.21(r)(14)). For example, the facility would update § 122.21(r)(3) to indicate the addition of the new unit, any new intakes associated with the new unit, expected operational characteristics, etc. For the owner or operator of a new unit and with an AIF greater than 125 mgd, the permit application materials under § 122.21(r)(9)–(13) are required. In those circumstances where data specific to the facility indicate that compliance with the requirements of paragraphs (e)(1) or (2) of § 125.94 for a new unit would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at issue, or would result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on local energy markets, the rule requires the submission of such data as part of § 122.21(r)(14). EPA notes that when a new unit increases an existing facility's AIF greater than 125 mgd, the permit application requirements also include § 122.21(r)(9) through (13). Further, facilities may need several years to complete studies and data collection and, depending on the types of controls selected, may need additional time to design and construct their technology. Thus while the rule requires the permit application for a new unit at least 180 days prior to commencing cooling water withdrawals, it is in the facility's best interest to submit this data well in advance in order to prevent any delays in the Director's review of permit application materials and subsequent issuance or renewal of the facility's NPDES permit. For the owner or operator of a new unit opting to comply via § 125.94(e)(2) the application materials required under § 122.21(r)(14) must demonstrate entrainment reductions equivalent to 90 percent or greater of the reduction that could be achieved through compliance with § 125.94(e)(1).

EXHIBIT VIII–2—SUMMARY OF PERMIT APPLICATION REQUIREMENTS FOR EXISTING FACILITIES ACCORDING TO EXISTING FACILITIES' CHOSEN METHOD FOR COMPLIANCE WITH IMPINGEMENT MORTALITY STANDARD

Compliance approach to impingement	§ 122.21 subsection							
	(r)(2)	(r)(3)	(r)(4)	(r)(5)	(r)(6)	(r)(6)(i)	(r)(6)(ii)	(r)(8)
Closed-cycle recirculating system	Yes	Yes	Yes	Yes	Yes	No	No	Yes.
Design intake velocity	Yes	Yes	Yes	Yes	Yes	No	No	Yes.
Actual intake velocity	Yes	Yes	Yes	Yes	Yes	No	No	Yes.
Existing offshore velocity cap	Yes	Yes	Yes	Yes	Yes	No	No	Yes.
Modified traveling screens	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes.
Combination of technologies	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes.
Impingement Mortality Performance Standard.	Yes	Yes	Yes	Yes	Yes	Maybe	Maybe	Yes.

EXHIBIT VIII–3—SUMMARY OF PERMIT APPLICATION REQUIREMENTS FOR EXISTING FACILITIES: ENTRAINMENT

Compliance approach to entrainment	§ 122.21 subsection						
	(r)(7)	(r)(8)	(r)(9)	(r)(10)	(r)(11)	(r)(12)	(r)(13)
Closed-cycle recirculating system	Yes	Yes	Var.[a]	Var.[a]	Var.[a]	Var.[a]	Var.[a]
Director BTA entrainment determination: facility AIF above 125 mgd.	Yes	Yes	Yes	Yes	Yes	Yes	Yes.
Director BTA entrainment determination: facility AIF 125 mgd or below.	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe.

[a] Director has the discretion to waive.

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In addition, the Director may set information requirements not included in today's rule to aid in best professional judgment permitting, such as will occur for entrainment at facilities below 125 mgd AIF, and for impingement and entrainment at existing facilities below 2 mgd DIF, neither of which are required by today's rule to submit items in § 122.21(r)(9) through (r)(13). The Director may find aspects of the permit application requirements to be relevant in such situations. A summary of each permit application requirement follows.[88]

1. § 122.21(r)(2) Source Water Physical Data

This requirement is unchanged from the Phase I rule and the 2004 Phase II rule. The facility is required to submit data to characterize the facility and evaluate the type of waterbody potentially affected by the cooling water intake structure. The applicant is required to submit a narrative description and scaled drawings showing the physical configuration of all source water bodies used by the facility, including areal dimensions, depths, salinity and temperature regimes, and other documentation that supports the determination of the waterbody type where each cooling water intake structure is located; identification and characterization of the source waterbody's hydrological and geomorphological features, and the methods used to conduct any physical studies to determine the intake's area of influence in the waterbody and the results of such studies; and locational maps. The Director uses this information to evaluate the appropriateness of any design or technologies proposed by the applicant.

2. § 122.21(r)(3) Cooling Water Intake Structure Data

This requirement is unchanged from the Phase I rule and the 2004 Phase II rule. This data is used to characterize the cooling water intake structure and evaluate the potential for impingement and entrainment of aquatic organisms. Information on the design of the intake structure and its location in the water column allows evaluation of which species and life stages might be subject to impingement and entrainment. A diagram of the facility's water balance is used to identify the proportion of intake water used for cooling, make-up, and process water, as well as any cooling water supplied by alternate sources, such as reuse of another facility's effluent. The water balance diagram also provides a picture of the total flow in and out of the facility, and is used to evaluate gray water, waste water, and other reuses in the facility. The applicant is required to submit a narrative description of the configuration of each of cooling water intake structure and where it is in the waterbody and in the water column; latitude and longitude in degrees, minutes, and seconds for each cooling water intake structure; a narrative description of the operation of each of cooling water intake structure, including design intake flows, daily hours of operation, number of days of the year in operation and seasonal changes, if applicable; a flow distribution and water balance diagram that includes all sources of water to the facility, recirculating flows, and discharges; and engineering drawings of the cooling water intake structure.

3. § 122.21(r)(4) Source Water Baseline Biological Characterization Data

This information is similar to that required in the Phase I rule. Existing facilities are required to characterize the biological community in the vicinity of the cooling water intake structure and to characterize the operation of the cooling water intake structures. This supporting information must include existing data if they are available. However, the facility may supplement the data using newly conducted field studies if it chooses to do so. The information the applicant must submit includes identification of data that are not available and efforts made to identify sources of the data; a list of species (or relevant taxa) for all life stages and their relative abundance in the vicinity of the cooling water intake structure; and identification of the species and life stages that would be most susceptible to impingement and entrainment. All species should be evaluated, including the forage base and those species most important in terms of significance to commercial and recreational fisheries. In addition, the applicant must identify and evaluate the primary period of reproduction, larval recruitment, and period of peak abundance for relevant taxa; data representative of the seasonal and daily activities (e.g., feeding and water column migration) of biological organisms in the vicinity of the cooling water intake structure. In addition, instead of the information required at § 122.21(r)(4)(vi), the owner or operator of an existing facility or new unit at an existing facility must identify all Federally-listed threatened and endangered species and/or designated critical habitat that are or may be present in the action area pursuant to § 125.95(f). The action area can generally be considered the area in the vicinity of impingement and entrainment at the cooling water intake structure. The applicant must also include documentation of any public participation or coordination with Federal or State agencies undertaken. If the applicant supplements the information with data collected using field studies, supporting documentation for the Source Water Baseline Biological Characterization Data must include a description of all methods and quality assurance procedures for sampling, and data analysis including a description of the study area; taxonomic identification to the lowest taxon possible of sampled and evaluated biological assemblages (including all life stages of fish and shellfish); and sampling and data analysis methods. The sampling or data analysis (or both) methods used must be appropriate for a quantitative survey and based on consideration of methods used in other biological studies performed in the same source waterbody. The study area should include, at a minimum, the area of influence of the cooling water intake structure. The applicant may also identify protective measures and stabilization activities that have been implemented and describe how these measures and activities affected the baseline water condition in the vicinity of the intake.

EPA is adding § 122.21(r)(4)(ix), (x) and (xi) to the Source Water Baseline Biological Characterization Data for existing facilities. Item (ix) simply defines the term ''Source Water Baseline Biological Characterization Data.'' EPA is requiring item (xi), identification of fragile species found at the facility. EPA notes that in contrast to the proposed rule, the permit application does not require submission of the proposed ''species of concern.'' EPA found that the term ''species of concern'' was too similar to terms as used in the context of T&E (threatened and endangered) species, and may cause confusion over existing Services or State requirements for such species. Further, despite EPA's efforts to distinguish between species of concern and RIS (representative indicator species) in the NODA (77 FR 34325, June 11, 2011), EPA found that many commenters were still confused by the language. Instead, EPA is adopting the term ''fragile species'' and using the term exactly as it is used with the impingement mortality data and criteria used in calculating the

[88] Where a closed-cycle recirculating system withdraws greater than 125 mgd AIF, the information required in § 122.21(r)(9) to (13) is required, unless the Director reduces or waives some or all of the information required.

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impingement mortality standards of the rule. The definition for ''fragile species'' at § 125.92 is a species of fish or shellfish that has an impingement survival rate of less than 30 percent even when the BTA technology of modified traveling screens are in operation. EPA has identified fragile species in the Chapter 11 of the TDD for the final rule. Further, EPA is providing examples, in the list of 14 specific species in today's regulatory definition as a non-exclusive list. This list includes only those species specifically analyzed as part of the performance standards development. If a permit applicant can sufficiently demonstrate a record basis, the permitting Director may deem a particular species to be a fragile species for the purpose of a particular permit.

American shad (*Clupeidae*), bay anchovy (*Engraulidae*), and blueback herring (*Clupeidae*) belong to families that are specifically identified in the TDD Chapter 11 as examples of species that may be, at the Director's discretion, excluded from performance standards on the basis of impingement survival. As another example, threadfin shad (a species not specifically identified as fragile in today's rule) are prone to fall die-off when the water temperature reaches 42 degrees. The EPA does not intend for such naturally occurring mortality to be counted against a facility's performance in reducing impingement mortality. EPA is aware of limited success in flow reduction and behavioral deterrent systems in protecting fragile species. However, there are no demonstrated and available technologies for industry as a whole to address fragile species. EPA has long recognized these species as having low survival rates under the best of conditions, and established different mechanisms to address these in today's final rule. Today's BTA for impingement mortality allows the Director to establish site-specific controls under § 125.94(c)(9) to address fragile species.

EPA notes the change in terminology to ''fragile species'' eliminates the proposed rule burden on States to review and approve each facility's site-specific species of concern, and eliminates confusion over any T&E or RIS that may be subject to more stringent requirements under other Federal, State, and Tribal law. Further, use of ''fragile species'' instead of ''species of concern'' greatly increases the transparency of the Agency's impingement mortality performance standards.

In addition, EPA notes that § 122.21(r)(4)(vi) requires the applicant to submit information on all threatened and endangered species, not just those T&E species that are fish or shellfish. Examples of T&E species that are not fish or shellfish are corals, sea turtles and marine mammals.

4. § 122.21(r)(5) Cooling Water System Data

The Director uses this data in determining the appropriate standards that would be applied to the facility. Facilities are able to use this information, along with the water balance diagram required by § 122.21(r)(3), to demonstrate the extent to which flow reductions have already been achieved at the facility level. The applicant must provide the following information for each cooling water intake structure they use: A narrative description of the operation of the cooling water system and its relationship to cooling water intake structures (including the use of helper towers); the proportion of the design intake flow that is used in the system including a distribution of water used for contact cooling, non-contact cooling, and process uses; a distribution of water reuse (to include cooling water reused as process water, process water reused for cooling, and the use of gray water for cooling); description of reductions in total water withdrawals including cooling water intake flow reductions already achieved through minimized process water withdrawals; description of any cooling water that is used in a manufacturing process either before or after it is used for cooling, including other recycled process water flows; the proportion of the source waterbody withdrawn (monthly); the number of days of the year the cooling water system is in operation and seasonal changes in the operation of the system, if applicable. The applicant must also submit a description of existing impingement and entrainment technologies or operational measures and a summary of their performance, including for example reductions in entrainment due to intake location and reductions in total water withdrawals and usage, and efficiencies in energy production for each producing unit that result in the use of less cooling water, including for example combined cycle and cogeneration. For example, the applicant may provide comparative density data for the intake to demonstrate the extent to which location of the intake has reduced adverse environmental impact. The additional information at § 122.21(r)(5)(iii) is specific to those process units that use cooling water for purposes other than power generation or steam, and where the owner or operator intends to comply with the BTA for IM through either the use of flow reduction measures or the reuse of other water for cooling purposes.

5. § 122.21(r)(6) Chosen Method of Compliance With Impingement Mortality Standard

Today's final rule is flexible in providing seven different compliance options for meeting impingement mortality requirements. Under § 122.21(r)(6), the facility must identify its approach to meet the impingement mortality standards. The facility must identify the compliance method for the entire facility or, alternatively, the compliance method for each cooling water intake structure at the facility. Finding it to be unnecessary because the facility will already have a set of requirements to meet based on its chosen method of compliance, EPA has eliminated the proposed requirement for a separate impingement mortality reduction plan. In addition, monitoring and studies conducted under the reduction plan is no longer required by all facilities. Instead today's final rule specifies data collection requirements only in those instances where the facility must demonstrate a particular performance outcome as described below.

Facilities choosing to comply with § 125.94(c) by operating a modified traveling screen (under § 125.94(c)(5)) must submit an impingement technology performance optimization study under § 122.21(r)(6)(i). The site-specific study must demonstrate the modified traveling screen as defined at § 125.92 has been optimized to minimize impingement mortality. The study must include a minimum of two years of biological data collection. This time frame is consistent with the requirements at paragraph (r)(4)(iv) of § 122.21 to identify primary periods of reproduction and peak abundance, as well as § 122.21(r)(4)(v) to provide data representative of the seasonal activities, both of which would require at least one year worth of data collection. EPA expects facilities will either use existing biological data already required under § 122.21(r)(4) to complete their site-specific impingement studies, modify their biological data collections under § 122.21(r)(4) to be comprehensive and inclusive, use existing performance studies, or collect supplemental data necessary to make their demonstrations. If a facility is using previously collected data or studies that are more than 10 years old, the facility must demonstrate the data is still relevant and representative of the facility. If a facility

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intends to return organisms to a different waterbody from which they are withdrawn, a request for consideration of this must be made to the Director under § 122.21(r)(6).

The rule specifies sampling at least monthly during the two year data collection effort of the impingement technology performance optimization study, and requires documentation of methods used including counting of moribund organisms, latent mortality, holding times, and counting of entrapment. The Director may establish more frequent collection, as well as specify sampling methods and additional protocols to be used. If the facility intends to return fish and shellfish to a different waterbody than the source waterbody that is used to withdraw cooling water, EPA expects this would be identified as part of § 122.21(r)(6)(i). While EPA does not expect this situation occurs very frequently, the permit application information at § 122.21(r)(6)(i) along with (r)(4) would provide the Director the information needed to determine whether such a return location is appropriate.[89] If the site-specific impingement study demonstrates the modified traveling screen (as defined at § 125.92) has been optimized to minimize impingement mortality, the Director may then determine the modified traveling screen is the best technology available for impingement mortality at the site. The Director would then include permit conditions that ensure the technology will perform as demonstrated. If the Director determines that additional data is required to identify permit operating conditions, the Director has the authority to establish such requirements under § 125.95(d). Note that the EPA envisions the study will function to optimize performance, which is not the same as requiring a study merely demonstrating a specific numeric level of performance for impingement mortality has been or can be achieved. For the majority of facilities, EPA expects annual performance using modified traveling screens will exceed the Agency's calculated average annual performance standards for impingement mortality. Several examples of modified traveling screens in EPA's record show annual performance for impingement mortality that is superior to the impingement mortality performance standard (e.g., lower than 10 percent).

Similarly, facilities choosing to comply with § 125.94(c) by operating a system of technologies (under § 125.94(c)(6)) that will achieve the impingement mortality standard must submit a impingement technology performance optimization study under § 122.21(r)(6)(ii). The site-specific study must provide a description of the technologies, operational measures, or sampling approaches or any combination of them to be used to meet the BTA for impingement mortality. The study must demonstrate that the system of technologies has been optimized to minimize impingement mortality. EPA notes the ''system'' may consist of one or more technologies already in place, or may be combined with newly installed technologies. Further, the study must include a minimum of two years of biological data collection, as just described.

The EPA is aware that it is possible for a facility to reduce its rate of impingement, but the same number of impinged fish die. This has the unintended consequence of increasing the percent impingement mortality calculated by the facility. EPA does not intend for such facilities to be penalized for significant reductions in impingement rates obtained through existing technologies and practices in place. Therefore, one difference in the required study for the system of technologies compliance alternative (as compared to the study required for modified traveling screens) is an understanding that operational measures, best management practices, intake location, and other technologies do not always lend themselves to direct impingement mortality measurements or data collection. Thus the study can include flow measurements and monitoring the rate of impingement (as opposed to directly monitoring mortality) as described below.

If the facility chooses to rely on credit for reductions in the rate of impingement already achieved, the impingement technology performance optimization study must document the reductions to be used as credit. The estimated reductions in impingement must be based on a comparison of the facility to a once-through cooling system with a traveling screen located on the shoreline of the source waterbody. For example, a facility with an offshore intake, an intake canal, or an intake located immediately downstream of a dam in a cold water stream, could demonstrate the population of fish at the intake is lower in these areas, resulting in lower rates of impingement. This provision is intended to allow a facility that conducted or completed a baseline characterization under the Phase II rule to use that same information as part of their demonstration under this rule.

As discussed in Section VI, EPA has identified flow reduction as one of the best ways to reduce both impingement and entrainment. Today's final rule, as part of the system of technologies compliance option at § 125.94(c)(6), provides the owner or operator of a facility the opportunity to demonstrate flow reduction as part of meeting the IM standards. If the facility chooses flow reduction to reduce impingement, the study at § 122.21(r)(6)(ii) must include two years of intake flows measured daily. This flow information plus the data collected under § 122.21(r)(4)(iv) would be used to document how the flow reduction results in a reduced rate of impingement, as well as documenting the extent to which such reductions are seasonal or intermittent. Many pumps operate at only one speed, which doesn't allow the facility to adjust its intake flow to changing conditions. As a potential application of § 125.94(c)(6), EPA is aware of a manufacturing facility that installed multiple pumps of different sizes, and the operator only utilized those pumps that were necessary to obtain the exact amount of cooling water needed. As another example, variable speed drives offer many facilities an opportunity to reduce their intake flows by as much as 10 percent. Variable speed drives are available at all facilities, and EPA expects variable speed drives will be considered when replacing existing recirculating pumps; however, EPA also acknowledges variable speed drives may not be practical in all cases. Nevertheless, EPA expects variable speed drives will be considered by the Director when establishing entrainment requirements under today's final rule. EPA provided an example of how a facility would receive credit for existing technologies in the NODA (see 77 FR 34322, June 11, 2011). An additional sample calculation that includes flow reduction is provided later in this section.

The study must identify each of these contributing components, and requires the calculation of the impingement mortality reflecting each component of the system. The impingement technology performance optimization study must demonstrate the system of technologies has been optimized to minimize impingement mortality. In addition, the study must document the percent impingement mortality

[89] For example, the St. Lucie generating facility determined that this arrangement was not appropriate at their site; see DCN 10–6515. The Brunswick facility, has a fish return flume that goes to a tributary rather than the intake canal or the river. This arrangement places the aquatic organisms away from the intake canal and in a more gentle water environment to increase the organisms' survival; see DCN 10–6569.

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reflecting optimized operation of the total system of technologies, operational measures, and best management practices at § 122.21(r)(6)(ii)(D). The Director may then determine the system of technologies is the best technology available for impingement reduction at the site. The Director would then include permit conditions that ensure the technology will perform as demonstrated.

6. § 122.21(r)(7) Entrainment Performance Studies

EPA proposed that a facility must submit all previously conducted performance studies, but has revised this provision in the final rule to include only entrainment related studies. Impingement performance studies, where relevant, are already part of the permit application at § 122.21(r)(6). This avoids imposing a requirement on all facilities to submit previous impingement studies that may be unnecessary, and eliminates a burden on the Director to review all such studies, many of which may no longer be relevant.[90] Under today's final rule, the applicant must submit a description of any biological survival studies conducted at the facility and a summary of any conclusions or results, including the following: site-specific studies addressing technology efficacy, through-facility entrainment survival (distinguished for eggs and larvae), entrainment analyses, or studies conducted at other locations including a justification as to why the data are relevant and representative of conditions at the facility. Because of changes in the waterbody over time, studies older than 10 years must include an explanation of why the data are still relevant and representative of conditions at the facility. If the data are no longer relevant and representative, the Director may reject the data. The Director uses such studies when establishing technology-based requirements for entrainment. Permit applicants are not required to conduct new studies simply to fulfill this requirement. This requirement is rather aimed at obtaining results for relevant studies that have already been conducted as part of past permit proceedings or for other purposes even if those studies were not completed or conducted entirely as planned.

[90] For example, the study may be old and no longer representative, the study may address a pilot study of a technology no longer under consideration by the facility, or the facility may have already selected one of the compliance methods for IM based on pre-approved technologies at § 125.94(c)(1), (2) or (4).

7. § 122.21(r)(8) Operational Status

The applicant must submit a description of the operational status of each unit for which a cooling water intake structure provides water for cooling, including the following: Descriptions of each individual unit's operating status including age of the unit, capacity utilization for the previous five years (including any unusual or extended outages that significantly affect the facility's reporting of flow, impingement, or other data), and any major upgrades completed in the past 15 years (e.g., boiler or condenser replacement, changes to fuel type, a new production line); a description of completed, approved, or scheduled uprates and NRC (Nuclear Regulatory Commission) relicensing status for nuclear facilities; a description of plans or schedules for decommissioning or replacement of units; and a description of current and future production schedules for manufacturing facilities. The Director will use such information in determining the BTA for entrainment as well as when establishing compliance schedules. For example, where the remaining useful plant life is considerably shorter than the useful life of an entrainment technology or where a facility has a planned retirement within the next permit cycle, this information is useful to support a determination regarding that specific entrainment technology. This information would also be used under § 125.94(c)(12) to document infrequently used power generating units that operate with a capacity utilization of less than 8 percent averaged over a 24-month block contiguous period and that the Director may therefore determine warrants IM controls less stringent than § 125.94(c)(1) through (c)(7). With respect to entrainment, the BTA for entrainment is determined by the Director for each site, and energy reliability is one factor the Director may consider when establishing entrainment controls (see § 125.98(f)(3)). EPA expects the information submitted on energy reliability will be considered by the Director when making a BTA determination for entrainment for low CUR units.

8. § 122.21(r)(9) Entrainment Characterization Study

Facilities that withdraw greater than 125 mgd AIF must develop a study that includes a minimum of two years of entrainment data collection. EPA envisions the facility would extend the data collection methods and frequency to develop the source water characterization already required by § 122.21(r)(4) to develop the Entrainment Characterization Study. The study would include complete documentation of the data collection period and frequency of entrainment characterization, and an identification of the organisms sampled to the lowest taxon possible. The data collection must be representative of the entrainment at each intake, and the study must document how the location of the intake in the waterbody and the water column are accounted for. The study must document the intake flows associated with the data collection. Consistent with the permit application requirements requiring biological data collection at § 122.21(r)(4) and (6), EPA requires at least two years of data to sufficiently characterize annual, seasonal, and diel variations in entrainment, including variations related to climate, weather, spawning, feeding, and water column migration. Also consistent with the permit application requirements at § 122.21(r)(4) and (6), facilities may use historical data that are representative of current operation of the facility and conditions at the site with documentation regarding the continued relevance of the data. The study must include analysis of the data to determine total entrainment and entrainment mortality. Documentation in the study must include the method in which latent mortality would be identified, and all methods and quality assurance/quality control procedures for sampling and data analysis would be described. The sampling and data analysis methods must be appropriate for a quantitative survey.

This information will help the Director determine the site-specific BTA for entrainment. For facilities with no entrainment technologies currently in place, this information characterizes the total potential for entrainment. The information can also be used to demonstrate that technologies and other measures already in place, or site-specific factors such as intake location or design, already reduce entrainment. For example, abundance data might demonstrate lower comparative densities that can significantly lower entrainment rates. The information could also be used by new units under § 125.94(e)(2) to demonstrate that an alternative technology or combination of technologies reduce entrainment at that site to a level commensurate with closed-cycle cooling.

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9. § 122.21(r)(10) Comprehensive Technical Feasibility and Cost Evaluation Study

The owner or operator of the facility must submit an engineering study of the technical feasibility and incremental costs of candidate entrainment control technologies. The study must include an evaluation of technical feasibility of closed-cycle cooling and fine-mesh screens with a mesh size of 2 mm or smaller, reuse of water or alternate sources of cooling water, and any other entrainment reduction technologies identified by the applicant or requested by the Director. This study must include a description of all technologies and operational measures considered (which could include alternative designs of closed-cycle recirculating systems such as natural draft cooling towers, hybrid designs, compact or multi-cell arrangements, or the conversion of helper towers to a fully recirculating system); and documentation of factors that make a candidate technology impractical or infeasible for further evaluation. For example, a discussion of land availability might include an evaluation of adjacent land, and acres potentially available because of generating unit retirements, production unit retirements, other buildings and equipment retirements, ponds, coal piles, rail yards, transmission yards, and parking lots; decommissioning of existing units; repurposing of existing land uses; documentation that insufficient acres are available on-site; and evidence of the feasibility of the purchase or other acquisition of property adjacent to the facility.

For the analysis of water reuse and use of alternate sources of cooling water, the owner or operator must examine the available alternatives for reuse of effluent from within the facility or from other dischargers in the vicinity. The volume of water available need not be for the full intake flow; reuse of water could contribute to a partial reduction in flow at the facility. Additionally, if the facility were to retrofit to a closed-cycle system, the significant reduction in flow may make nearby alternative sources more feasible. This analysis should include an estimate of the cost to build any new infrastructure (e.g., piping, pump houses) and the ongoing operational costs (e.g., pump costs) for the Director's consideration.

The final rule requires that the cost information be presented as both the facility's compliance costs and the social costs, and in net present value (NPV) terms and the corresponding annual value. Social costs are the costs estimated from the viewpoint of society, rather than individual stakeholders. Social cost represents the total burden imposed on the economy; it is the sum of all opportunity costs incurred. See Chapter 8 of EPA's 2010 Guidelines for Preparing Economic Analyses (DCN 10–3258). Some adjustments to facility compliance costs to produce social costs cause them to be higher than compliance costs, while other cause social costs to be lower. Although a facility makes investment decisions by taking tax consequences into account (after-tax costs), the favorable tax treatment of investments is viewed as a transfer and not a real resource cost, thus pre-tax costs are used in social cost analysis. From society's viewpoint, costs in the future must be amortized and discounted to net present value using a social discount rate, rather than a market cost of capital as reflected in market interest rates. The Office of Management and Budget (OMB) Circular A–4 (DCN 10–3266) instructs agencies to use both 3 percent and 7 percent discount rates. Certain administrative costs are not borne by a facility, but rather by the Director, and are social costs. Compliance costs include the facility's administrative costs, including costs of permit application, while the social cost adjustment includes the Director's administrative costs. EPA has estimated the Directors' administrative costs in the ICR for the final rule, and describes the methodology for estimating these costs in detail in the EA. Facilities may adopt a similar approach to including Director's administrative costs in their social cost estimates. In addition, this component is not expected to be large or to vary significantly across technology options considered.

From a facility's viewpoint, downtime costs include lost net revenue, while from society's viewpoint, if another facility is dispatched or inventory of manufactured goods can be sold, the only social cost of downtime is any increase in marginal costs of production at other facilities dispatched or the cost of holding inventory. Unless a facility can demonstrate that its costs of compliance will result in lower overall supply in the markets in which its products are sold, and that the effect of the lowered supply is an increase in market price and lower quantity of product sold, the facility should not make a social cost adjustment to reflect these larger market impacts.

In addition to the required social costs, the owner or operator may choose to provide facility level compliance costs; however, such costs must be provided and discussed separately from social costs. The cost evaluation component of this study must include engineering cost estimates of all technologies considered above and also discuss and provide documentation of any outages, downtime, energy penalties or other effects on revenue. The cost evaluation should be based on least-cost approaches to implementing each candidate technology while meeting all regulatory and operational requirements of the facility. Depreciation schedules, interest rates, further consideration of remaining useful life of the facility as discussed in § 122.21(r)(8), and any related assumptions must be identified. The owner or operator of the facility must obtain peer review of the Comprehensive Technical Feasibility and Cost Evaluation Study, as described in Section 12.

10. § 122.21(r)(11) Benefits Valuation Study

The owner or operator of the facility must submit a detailed discussion of the benefits of the candidate entrainment reduction technologies evaluated in § 122.21(r)(10) and using data in the Entrainment Characterization Study in § 122.21(r)(9). Each category of benefits should be described narratively, and when possible benefits should be quantified in physical or biological units and monetized using appropriate economic valuation methods. This includes incremental changes in the impingement mortality and entrainment of individual fish and shellfish for all exposed life stages, estimation of changes in stock and harvest levels of commercial and recreational species, and description of any monetization. This may include monetization using market values, market proxies (*e.g.,* models based on travel costs or other methodologies), benefits transfer and stated preference methods. Benefits that cannot be monetized should be quantified where feasible and discussed qualitatively where not. The study must identify increased or decreased thermal discharges, and must evaluate the potential changes in facility capacity, operations, and reliability due to relaxed permitting constraints related to thermal discharges. The study must also include discussion of recent mitigation efforts already completed and how these have affected fish abundance and ecosystem viability in the intake structure's area of influence. Finally, the study must identify other benefits to the environment and the community, including improvements for mammals, birds, and other organisms and aquatic habitats. The owner or operator of the facility must obtain peer review of the benefits evaluation study, as described in Section 12. EPA expects peer

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reviewers to have appropriate qualifications (*e.g.,* fisheries biologist, economist) for the subject matter. The Director may consult with EPA and Federal, State and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure(s) to determine which peer review comments must be addressed by the final study. The dollar values in the social benefits analysis should be based on the principle of willingness-to-pay (WTP), which captures monetary benefits by measuring what individuals are willing to forgo in order to enjoy a particular benefit. While the Director must consider benefit and cost information, the Director will also determine if this information is of sufficient rigor to make a decision on entrainment controls on the basis of this information. For instance, the Director may decide not to rely on benefit-cost information in establishing the entrainment controls when the benefits analysis includes only a qualitative discussion of nonuse benefits. Willingness-to-pay for nonuse benefits can be measured using benefits transfer or a stated preference survey. However, the rule does not require the Director to require a facility owner or operator to conduct or submit a stated preference survey to assess benefits.

11. § 122.21(r)(12) Non-Water Quality Environmental and Other Impacts Assessment

The owner or operator of the facility must submit a detailed discussion of the changes in non-water quality environmental and other factors attributed to technologies or operational measures, or both, considered. These changes may include, for example, increases or decreases in the following: Energy consumption; air pollutant emissions and their health and environmental impacts; noise; safety concerns, such as the potential for plumes, icing, and availability of emergency cooling water; grid reliability, including an estimate of changes to facility capacity, operations, and reliability due to cooling water availability; consumptive water use (including effects of surface water evaporation of thermal discharges); and facility reliability, such as production of steam and impacts to production based on process unit heating or cooling. The owner or operator of the facility must provide for peer review of the Non-Water Quality Environmental and Other Impacts Assessment as described in the following section.

12. § 122.21(r)(13) Peer Review

The owner or operator of the facility must provide for peer review of the permit application studies required at § 122.21(r)(10) Comprehensive Technical Feasibility and Cost Evaluation Study, § 122.21(r)(11) Benefits Valuation Study, and § 122.21(r)(12) Non-Water Quality and Other Impacts Assessment. While facilities that withdraw more than 125 mgd AIF must conduct these studies and therefore must provide for peer review, facilities that withdraw equal to or less than 125 mgd AIF may have study requirements including peer review as determined by the Director. In today's final rule, EPA did not adopt separate peer review requirements for the Entrainment Characterization Study at § 122.21(r)(9), because this data would be included in the Comprehensive Technical Feasibility and Cost Evaluation Study, Benefits Valuation Study, and Non-Water Quality and Other Impacts Assessment, and these studies are already subject to peer review. For these reasons, EPA reduced the burden in the final rule by eliminating the peer review requirement for entrainment characterization.

EPA recognized at proposal that in many cases it is more efficient for permit applicants to combine the required studies into one document and have them reviewed holistically by a single set of peer reviewers. Such an approach is allowed by the final rule, as long as the peer review panel has the background appropriate to conduct a complete and combined review and the Director approves.

The Director may consult with Federal, State and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure(s). Further, the Director may require the owner or operator of the facility to include additional peer reviewers of the studies. EPA expects peer reviewers to have appropriate qualifications (e.g., in the fields of biology, engineering) for the subject matter. An explanation for any significant reviewer comments not accepted must be included in the final study submission. Additional guidance on conducting peer review is available on EPA's Peer Review Program Web site at *www.epa.gov/peerreview.*

13. § 122.21(r)(14) New Units

New units at existing facilities must identify the compliance method for the new unit under the permit application requirements at § 122.21(r)(14). Where the facility complies with BTA standards for entrainment at § 125.94(e)(1) by reducing its intake flows commensurate with that of a closed-cycle recirculating system (as defined at § 125.92(c)(1)), the BTA standards for impingement mortality will have been met by § 125.94(c)(1). To comply with the alternative at § 125.94(e)(2), there must be a demonstration that entrainment reductions equivalent to 90 percent or greater of the reductions that could be achieved through compliance with § 125.94(e)(1).[91] In this case, permit application requirement § 122.21(r)(14) requires this demonstration to include the Entrainment Characterization Study at § 122.21(r)(9). The Director may determine additional data and information, including data collection, is necessary to make the demonstration.

D. When are permit application studies due?

The owner or operator of a facility applying for reissuance of a permit must submit the information required at § 122.21(r) to the Director no later than 180 days before the current permit expires. Those facilities that were subject to the section 316(b) Phase II rule from February 16, 2004 until suspension of that rule on July 9, 2007 were already collecting some information required at § 122.21(r). EPA has structured this rule to take advantage of those data and expects facilities to use them when they satisfy requirements for permit applications.

In some cases, required permit application information might have been collected, but reports might not have been generated or finalized prior to the rule suspension in 2007. Further, facilities not subject to the Phase II rule (e.g., existing power plants below 50 mgd DIF and all existing manufacturers) might not have collected this information or might not have collected information to identify permit operating

[91] Note that a new unit may construct a new intake structure or utilize capacity from an existing intake structure. For the former, the requirements of § 125.94(e)(1) are simple to conceptualize and apply. But for the latter, EPA clarifies that the new unit requirements only apply to that portion of the flow that is serving the new unit. For a new unit using an existing intake structure that chooses to comply using § 125.94(e)(1), demonstrating that the new unit achieves the required reduction in flow should be a relatively simple exercise in identifying intake flows and the distribution of cooling water from the intake structure. For a new unit using an existing intake structure that chooses to comply using § 125.94(e)(2), the facility would demonstrate that it has reduced entrainment for that portion of the intake flow serving the new unit by 90 percent; the facility would not be required to reduce entrainment for the flow of the entire intake structure by 90 percent, unless the Director makes such a site-specific determination for entrainment at the existing units as well.

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conditions. In those cases, facilities would have to collect additional data in order to have two years of biological data collection. EPA expects associated studies and reports will take several additional months to complete. For this reason, EPA has established a provision for permit application submittal for a permit expiring prior to July 14, 2018, allowing the Director flexibility to delay application requirements based on a showing by the owner or operator that it could not develop the information by the time required for submission of the permit application. The Director would then establish a schedule for submission of the delayed permit application requirements. EPA notes that the Director has the discretion to require additional studies, data collection, or an on-site inspection as part of the permit process.

Facilities whose permit expires after July 14, 2018 would submit all required materials in § 122.21(r) with their permit renewal application.

New units at existing facilities must submit the information required at § 122.21(r) to the Director no later than 180 days before commencing operation of the new unit. Because these units are being constructed at a facility that is already operating, the facility will have already submitted many of the permit application materials. The addition of a new unit would require an update of or supplement to permit application materials that have already been submitted. New units take significant time and resources to plan, design, and construct; therefore the final rule does not have a provision to waive permit application requirements based on a showing by the owner or operator that it could not develop the information by the time required for submission of the permit application. For permit renewals subsequent to the first permit issued under today's rule, the new unit would be included in the assessment of the entire facility and would no longer require unique permit application submissions. As discussed previously, the owner or operator is encouraged to submit applications well in advance of the 180 day requirement to avoid delay.

EPA is aware that some intake structures withdraw from a manmade lake or reservoir that is stocked and managed by a State or Federal natural resources agency. In some cases, the biological characterization of the source water is heavily influenced by the actions of the natural resources agency. Further, the results of biological data collection and studies may be confounded by such actions. Today's final rule at § 125.95(a)(3) gives the Director discretion to waive some or all of the permit application requirements of § 122.21(r) in such circumstances.

In permit terms subsequent to the first permit issued under the final rule, the facility will re-submit the § 122.21(r) permit application studies, while the rule still includes two years of biological data collection for some facilities. In this manner, the biological characterization over time would be routinely evaluated, i.e., every 5 years under a standard permit cycle. To reduce the burden of such data collection, however, the final rule provides that the owner or operator of a facility may submit a request to the Director to reduce the information required. See 40 CFR 125.95(c). In most cases, EPA anticipates the facility would make any such request prior to conducting its two years of biological data collection. Therefore the request for reduced information requirements must be submitted to the Director at least two years and six months before the expiration of the facility's NPDES permit. The Director may approve such a request if conditions at the facility and in the waterbody remain substantially unchanged since the previous permit application.[92] EPA expects the Director would assess the relevant previously submitted information and determine whether it remains representative of current source water, intake structure, cooling water system, and operating conditions. Accordingly, the Director may accept or reject any part of the request.

E. How will the director determine the best technology available for minimizing adverse environmental impacts?

1. Review and Approval of Permit Application Materials

Under today's rule, the Director will review all materials submitted by an existing facility with its permit application to determine appropriate NPDES permit conditions and requirements to minimize impingement mortality and entrainment. As stated at 40 CFR 125.98(a), the Director shall not issue a permit before receiving a permit application form and any supplemental information which are completed to his or her satisfaction (see existing Permit Application and Special NPDES Program Requirements at 40 CFR 122.21(e)).

Facilities with a design intake flow at or below 2 mgd will continue to have permit conditions set on a case-by-case, best professional judgment basis under 40 CFR 125.90(b) and 401.14. For such facilities, however, the Director may choose to apply some portions of the permit application conditions in today's rule to aid in the BPJ determination.

The Director is encouraged to expeditiously provide any comments on submitted materials so the facility can make responsive modifications to its information gathering activities. For permit applications subsequent to the first permit issued under today's rule, the Director could indicate whether reduced or different information must be submitted with the permit application. More specific responsibilities are described below:

a. If the Director has made a BTA determination for entrainment before the effective date of the rule, and substantially the same information was already submitted and considered by the Director in making that determination, under § 125.98(g) the Director may proceed with the Determination of BTA without requiring the owner to submit the information required in § 122.21(r).

To clarify further, EPA has included a ''transition'' provision at § 125.98(g) of today's rule that makes it clear that for any facility that has submitted a permit application before the effective date of the regulation, the Director may select the best approach to development and implementation of the next permit. These provisions are intended to avoid any unnecessary delay in recently submitted permit applications or draft permits. EPA expects that facilities will continue with any data collection requirements, study requirements, and schedules in recently issued permits.

b. If the Director establishes a compliance schedule under § 125.94, the Director will establish a schedule that sets requirements as soon as practicable. In establishing the schedule, the Director is encouraged to consider the extent to which those technologies proposed to be implemented to meet the requirements of § 125.94(d) will be used, or could otherwise affect a facility's choice of technology, to meet the requirements of § 125.94(c). Impacts of thermal discharges, along with other stressors, might be a relevant consideration when assessing benefits of technologies to reduce impacts of cooling water intakes or discharges. The Director is also encouraged to consider energy reliability, transmission capacity, and

[92] The presence of any habitat designated as critical, or species listed as threatened or endangered after issuance of the current permit (whose range of habitat or designated critical habit includes waters where a facility intake is located) constitutes potential for a substantial change that must be addressed by the owner/operator in subsequent permit applications, unless the facility received an exemption pursuant to 16 U.S.C. 1536(o) or a permit pursuant to 16 U.S.C. 1539(a) or there is no reasonable expectation of take.

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grid requirements when establishing a schedule for electric power generating facilities. The Director may confer with local and regional electric power agencies and state utility regulators when establishing a schedule for electric power generating facilities (see DCN 10–6860 for information on the approach taken by California). The Director may determine that extenuating circumstances (e.g., lengthy scheduled outages, future production schedules) warrant establishing a different compliance date for any manufacturing facility.

c. The Director will review the permit application materials and studies submitted under § 122.21(r) and determine which entrainment controls are appropriate. Factors that must be considered and factors that may be considered in making the determination are provided at § 125.98. The Director must issue a written explanation for the BTA determination and must make this determination, and any other information submitted by third parties, available with the permit for public review. This determination is expected to be issued as part of the permit's statement of basis under 40 CFR 124.7.

2. Role of Social Cost-Benefit Analysis in Permit Determinations

In deciding what technology to require a permittee to install to address entrainment, the Director may undertake an evaluation of social costs and benefits of implementing such requirements. This analysis will be based on the information submitted by the applicant, supplemented by any information submitted by third parties, and additional information as determined appropriate by the Director. EPA recognizes the resource limitations faced by permitting authorities and does not generally expect that the Director would develop additional information on which to base the evaluation of social benefits and costs, although the Director may opt to do so. This analysis should evaluate benefits and costs from the perspective of society as a whole, rather than costs and benefits accruing to limited parties (e.g., very local populations or the permittee, which presents a limited set of information to the Director).

It is also important to note that the stated preference survey conducted by EPA which was discussed in the June 12, 2012 Notice of Data Availability (77 FR 34927) was designed to estimate respondents' willingness to pay for changes in the health of fish populations and aquatic ecosystems and be statistically representative at large (regional and national) scales; the results were not designed to be statistically representative at the facility level for the assessment of benefits for individual site-level permitting decisions. Today's final rule does not require the Director to require a facility owner or operator to conduct or submit a stated preference survey to assess benefits. Further, the rule does not limit the Director's discretion to consider non-water quality impacts in determining whether further entrainment measures are justified.

A number of cost elements should be accounted for in assessing the social cost of entrainment technology implementation. These are summarized below.

a. Technology Installation Cost

These peer-reviewed engineering cost estimates of the physical construction of candidate entrainment technologies at the facility are required. These costs would be provided by the applicant under § 122.21(r)(10).

b. Installation Downtime Cost

Installation of closed-cycle cooling systems will often require facilities to take additional downtime beyond ordinary annual maintenance downtime. An estimate of downtime cost to the facility is required under § 122.21(r)(10). EPA expects a facility will document that portion of downtime that is incremental to any downtime the facility already incurs due to, for example, routine maintenance outages, overhauls, refueling, and periodic replacement of equipment that is at the end of its useful life. Downtime costs to the facility include the value of lost production (e.g., electricity) minus any variable cost savings, as well as any other costs to the facility associated with downtime (shutdown and startup routines, special maintenance protocols, etc.) minus any savings associated with downtime. If they are considered in the social costs analysis, downtime costs must be adjusted to reflect production made up by other facilities or firms, because these temper the real resource costs from society's viewpoint. The cost of downtime is determined on a different basis for social cost. Specifically, the cost of downtime to society is the cost incurred for other facilities and generating units to make up the electricity or manufactured goods that would have otherwise been generated by the facility minus the cost that would have otherwise been incurred by the facility incurring downtime. This difference in cost reflects the additional cost, if any, that society must pay to generate the replacement goods, and may differ substantially from the cost of downtime to the facility.

c. Energy Penalty Cost

Operation of closed-cycle cooling systems may impose an energy penalty. EPA is using energy penalty to mean only the opportunity costs associated with reduced power production due to derating (turbine backpressure). Energy penalty does not include the costs to operate pumps and fans associated with closed-cycle cooling, which are operation and maintenance costs (and covered below). Under well-established principles in benefit-cost analysis, the cost of the energy penalty to the facility is not the opportunity cost to society. Instead, the cost to society is the cost of generating the electricity, whether incurred by the regulated facility or another facility, that is no longer available for consumption because of the energy penalty. This cost may be incurred by the facility, if it can increase the energy input to, and output from, the generating unit to generate the electricity that is otherwise no longer available for consumption, or by another generating unit if the regulated unit cannot make up the electricity. In either case, the social cost of the energy penalty is the cost of generating the electricity that would otherwise be available for consumption except for the energy penalty. Again, an assessment of these costs would be determined under the § 122.21(r)(10) demonstration.

d. Operation and Maintenance Costs for the Entrainment Technology Equipment

The cost of energy to operate the entrainment technology for electric generators should appear in the operation and maintenance costs, along with other labor and materials costs. In the same way as described above, the social cost of the energy required to operate entrainment technology is the cost for generating this electricity, as it is otherwise no longer available for end-use consumption. This cost could be incurred by the regulated facility, if it has sufficient capacity to make up the loss, or by another facility, if the regulated facility is not capable of generating the electricity that is no longer available for end-use consumption.

e. Other Administrative Expenses

This includes additional permitting or reporting expenses, or both. For social costs, the estimate should include the costs to the facility and those expected to be incurred by the Director.

EPA has estimated the Directors' administrative costs in the ICR for the final rule, as explained in the EA, and

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facilities may adopt a similar approach to estimating these costs at the permit level. For assessing social cost, the cost elements outlined above would typically be accounted for on a real cost basis—that is, pre-tax and without adjusting for future inflation. Costs are tallied over an appropriate time frame, which will typically be the expected useful life of the technology installation or the remaining life of the facility, if less. Costs should be calculated as both net present value and annualized values, using an appropriate social discount rate. The applicant should document the basis for the discount rate chosen, and its methodology and calculations.

f. Benefits

In assessing the benefits of entrainment technology installation, the Director would assess the value to society from the reductions in impingement mortality and entrainment that would result from installation of a closed-cycle cooling system, fine mesh screens, or other entrainment technologies. All benefits, including monetized, quantified and qualitative benefits, should be considered in this assessment. The benefits assessment would typically look at a range of potential benefit categories, including increased harvest for commercial fisheries, increased use values for recreational fisheries, and nonuse values (existence and bequest values). The latter may be difficult to quantify or monetize. If appropriate data are available from benefits transfer or conducting stated preference studies or other sources that can be applied to the site being evaluated, these should be used to monetize nonuse values. Otherwise, nonuse values should be evaluated quantitatively and/or qualitatively. Quantitative analysis, even without monetization, can be quite useful in evaluating nonuse benefits. For example, quantifying impacts to forage and threatened and endangered species, and other indirect impacts on the aquatic environment, might allow the Director to derive a much more complete understanding of benefits as compared to a qualitative narrative, even if not directly comparable to monetary costs.

Quantifying and valuing the benefit categories listed above involves significant challenges, as described in the BA. For example, assessing the productivity and value of commercial fisheries involves estimating the expected increases in commercial yield of economically valued species over time as a result of reduced impingement mortality and entrainment, and valuing these at market prices minus any incremental production costs associated with the incremental catch. Similarly, assessing recreational use benefits involves estimating the improvements in recreational fishing opportunities resulting from reduced impingement mortality and entrainment, and assigning a value to these improvements. The value assignment is based on the estimated population profile—in particular, number and proximity to affected water resources—of recreational users, the availability of alternative competing water resources for recreational usage, and the resulting estimated change in demand for use and value of the affected water resources based on reduced impingement mortality and entrainment and increased recreational fishing performance. EPA acknowledges this could be difficult to do even on a site-specific basis.

Nonuse benefits, which encompass existence and bequest values, include impacts in such areas as population resilience and support, nutrient cycling, natural species assemblages, and ecosystem health and integrity. Nonuse values include improving the survival probability of a threatened or endangered species if present in the vicinity of the facility. Benefits might also need to be assessed beyond the vicinity of the facility's intake if migratory species are affected by the intake. Residual impacts of thermal discharges might also be appropriate to consider in the social benefits calculation.

In much the same way as described for the social cost assessment, social benefits are tallied yearly over the expected performance life of the compliance technology. This tallying should account for the ''phase-in'' of benefits (e.g., benefits may build up over time as the impingement mortality and entrainment reductions affect commercial fisheries productivity). Benefits are computed on a present value basis and annualized using an appropriate discount rate as described above. The same discount rate should be used for benefits and costs. Often, it is appropriate to calculate benefits and costs using more than one discount rate. For example, for regulatory impact analysis, OMB recommends that Federal agencies use both a 3 percent and a 7 percent rate. However, comparisons between specific benefit and cost numbers should always involve values computed using the same rate.

The resulting estimates of social cost and benefits must be considered in determinations on whether to require a permittee to install entrainment technology and the specific level of entrainment technology to be installed. The Director may reject otherwise available technologies as the BTA requirements for entrainment controls if the social costs of compliance are not justified by the social benefits, or if there are other adverse impacts that cannot be mitigated that the Director deems to be unacceptable. If all technologies considered have social costs not justified by the social benefits, or have unacceptable adverse impacts that cannot be mitigated, the Director may determine that no additional control requirements are necessary beyond what the facility is already doing. The Director should document the basis for such a determination and include it in the public notice for the draft permit.

3. Streamlined Process

The process for complying with the impingement mortality standards is expected to be highly streamlined. As shown in Exhibit VIII–1, EPA expects more than 99 percent of facilities will comply by one of the six compliance options that do not require continual biological compliance monitoring (one of the three compliance alternatives based on pre-approved technologies or one of the three streamlined compliance alternatives). If a facility chooses to comply by operating a modified traveling screen, the Director will review the impingement technology performance optimization study, including the identification of species, duration and structure of the study, and any monitoring requirements.

4. De Minimus Provision

The Director may, based on a review of data submitted under § 122.21(r), conclude that the documented rate of impingement at the cooling water intake structures is so low that no additional controls are warranted. As described in section I.A.H, low flow facilities may in particular be candidates for such consideration, although the authority of the Director is not limited to low flow facilities. The Director may want to consider facility withdrawal rates in relation to the mean annual flow of the river and possible co-location with other CWISs when making a de minimis determination. Notice of this determination would be included in the draft permit made available for public comment, and the Director's response to any comment on this determination must be included in the record for the final permit. EPA considers low rates of impingement to be measured as an organism or age-one equivalent count, and not as the effect of impingement on

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fish populations. The Director may require data collection to demonstrate support for a de minimis level of impingement. In addition, EPA does not expect that a de minimis exemption would apply to facilities with no technology present other than trash racks, a technology that nearly all facilities employ. In making a determination that no additional controls are warranted, the Director may wish to consider factors such as whether the waters are subject to a TMDL for an aquatic life use, the waters are not attaining a designated use, and there would be more than minor detrimental effects on threatened or endangered species or critical habitat. The Director will still establish proper operation and maintenance conditions in the permit whenever making a de minimis finding that no additional controls are warranted. EPA notes that the de minimis provision for impingement does not necessarily mean a facility has a de minimis level of entrainment. The life stages affected by impingement are different than those affected by entrainment, and low counts of impingeable life stages do not always mean the counts of entrained organism are similarly low. Since the entrainment requirements are already determined by the Director for each site, EPA concluded that specific regulatory language for de minimis entrainment was unnecessary.

5. Low Capacity Utilization Units

The Director may consider less stringent controls for intakes dedicated to low capacity utilization rate (CUR) power generating units. If an existing facility has a cooling water intake structure used exclusively for one or more existing electric generating units, each with an annual average capacity utilization rating of less than 8 percent averaged over a 24-month block contiguous period, the owner or operator may request that the Director establish BTA standards for impingement mortality for that cooling water intake structure which are less stringent than § 125.94(c)(1) to (c)(7). When determining the permit's IM requirements associated with the low CUR unit, the Director may consider, after conferring with any appropriate state co-regulators (such as public utility commissioners) and with regional transmission organizations, independent system operators or other planning authorities, the significance of the unit's operation to the overall reliability of electric power in the area.

In addition, in determining the IM requirements associated with a low CUR unit, the Director should consider any seasonal factors for affected species that might justify seasonal limits on the unit's operation, for example any increased impacts resulting from the unit's operation during spawning runs. Also, when considering the presence and potential effects to threatened and endangered species, the Director should consider whether the life stages present at the location are at risk of being impinged or entrained at the low CUR unit's cooling water intake.

In the event that the Director determines less stringent controls for intakes dedicated to low capacity utilization power generating units are appropriate, they should consider, at a minimum, the following in establishing controls:

Strategies for minimizing water withdrawal during stand by periods of operation, startup/shutdown, and on-line periods of operation;

The effectiveness of installing variable speed pump drives to reduce water withdrawals during all periods of operation, particularly during stand-by periods of operation; and

The effectiveness of installing alternative equipment (e.g. behavioral deterrents) to minimize impingement mortality.

The owner or operator would demonstrate whether they have an intake only serving one or more low capacity utilization power generating units in permit application requirements at § 122.21(r)(3) and (8). Under § 122.21(r)(6), the owner or operator would indicate a request that the Director establish alternative BTA standards that are less stringent than § 125.94(c)(1) through (7). EPA recognizes the contribution of peaking units in serving peak electricity demands, and maintaining a reliable electricity grid. However, if peaking units are in standby mode for long periods relative to periods when they are generating electricity, the result is a capacity utilization of the cooling water intake that is greater than the capacity utilization of the generator. Significant periods of standby could contribute to a greater impact on aquatic life. While the 8 percent capacity utilization is an industry standard that distinguishes those units making the greatest contribution to a smoothly functioning electricity grid, a Director may still determine that the impacts to aquatic life are significant enough to deny a request that BTA at that intake should be less stringent than § 125.94(c)(1) to (c)(7). EPA anticipates the Director will have the information necessary to determine BTA in such circumstances based on the permit application requirements, including but not limited to an identification of the number of days the cooling water system is in operation, flow on those days, and seasonal changes in the operation of the system under § 122.21(r)(5) and the biological information under § 122.21(r)(4).

As discussed previously, the Director will determine the BTA for entrainment for low CUR units on a site-specific basis. EPA expects that many of the same factors discussed above—including the significance of the unit's operation to the overall reliability of electric power in the area, the diversity of fuels available for the unit, and the impact of the costs of any potential entrainment requirements on the unit's cooling water intake structure on overall reliability of electric power in the area—will be relevant in making site-specific BTA entrainment determinations for low CUR units. The Director may consider the factors at § 125.98(f)(3) when making these determinations for low CUR units, which includes grid reliability, among other factors.

6. Monitoring

The Director will review any impingement mortality and entrainment monitoring reports submitted by the facility to ensure ongoing compliance. EPA is shifting toward an electronic discharge monitoring report system, and many of the impingement mortality and entrainment standards can be incorporated into the discharge monitoring report itself, rather than requiring a separate report. Except for facilities choosing alternatives § 125.94(c)(7), detailed biological data collection would only be included as part of the facility's permit application submission and not for compliance purposes. The Director has the discretion to request additional information, including inspection of the facility, at § 125.95(d) (*i.e.,* permit application and supporting information requirements) and § 125.96(c) (*i.e.,* additional monitoring requirements).

7. Nuclear Units

The rule includes a provision that permits the owner of a nuclear facility to demonstrate to the Director that compliance with the rule would result in a conflict with safety requirements for their facility. See § 125.94(f). EPA anticipates that this provision would be implemented as follows. Initially, the Director will draft a permit and will share the draft permit with the owner or operator of the nuclear facility. Upon reviewing the draft permit, the owner or operator will determine whether in their view a conflict with a safety requirement established by the Nuclear

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Regulatory Commission, the Department of Energy or the Naval Nuclear Propulsion Program exists. If a conflict exists, the owner or operator should communicate the conflict to the NRC, Department or Program and the Director. In all cases, whether a conflict exists or not, the Director should notify the NRC, Department or Program and the owner or operator of the facility that he or she wishes to informally confer regarding the permit. Such interactions should be scheduled, conducted and documented. Where a conflict is identified, the Director would make a site-specific BTA determination.

F. What are example permit conditions and compliance monitoring for impingement mortality?

As previously discussed, the owner or operator must comply with BTA standards as soon as practicable on a schedule of requirements established by the Director. EPA did not specify dates by which the BTA standards for impingement mortality must be met because the specific method of compliance with the BTA standards for impingement mortality is tied to the determination of BTA requirements for entrainment. Further discussion of this alignment of compliance deadlines is provided in Section A. Today's final rule provides for several methods of compliance with the BTA for impingement mortality. This section discusses each of the methods for compliance, how they follow from the permit application requirements at § 122.21(r), and any minimum monitoring and reporting requirements associated with each method.

1. Closed-Cycle Recirculating System

In this method of compliance, an existing facility must operate a closed-cycle recirculating system as defined at § 125.92(c). The facility would indicate the choice to use this compliance method under § 122.21(r)(6) in its permit application. As specified in § 122.21(r)(1), the facility would need to submit § 122.21(r)(9) through (13), if it exceeds 125 mgd AIF and these requirements are not waived by the Director. The information still required at § 122.21(r)(2) to (8) is considerably less burdensome. The monitoring must be representative of normal operating conditions, and must include measuring cooling water withdrawals, make-up water, and blowdown flows. The facility must monitor actual intake flows at a minimum frequency of daily, or may monitor the representative cycles of concentration at a minimum frequency of daily. These monitoring data would be used by the Director to determine that make-up and blowdown flows have been minimized. The owner or operator would submit these data with their existing DMR or equivalent state report. Facilities complying using closed-cycle cooling are not subject to biological compliance monitoring unless otherwise specified by the Director (see § 125.96(c)).

2. 0.5 Feet per Second Through-Screen Design Velocity

In this method of compliance, the facility must operate a cooling water intake structure that has a maximum design through-screen intake velocity of 0.5 feet per second. The facility must submit information under § 122.21(r) to the Director that demonstrates that the maximum design intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh could not exceed 0.5 feet per second. The maximum velocity must be achieved under all conditions, including during minimum ambient source water surface elevations (based on BPJ using hydrological data) and during periods of maximum head loss across the screens or other devices during normal operation of the intake structure.

EPA notes a cylindrical wedgewire screen, in general, is designed for 0.5 feet per second. In Phase II, EPA pre-approved wedgewire screens under specific operational conditions. Today's final rule simplifies the demonstration requirements for a facility employing cylindrical wedgewire screens to that of demonstrating the maximum design through-screen velocity is 0.5 feet per second. As another example, a facility may have pumping and piping constrictions that physically limit the design intake velocity to less than 0.5 feet per second. The Director may choose to establish permit conditions that address the physical limitations of the intake, such as requiring a pump be removed from service, or that only one of two (redundant) pumps may operate at any time. Facilities choosing to comply under this section do not have monitoring requirements under this section.

3. 0.5 Feet per Second Through-Screen Actual Velocity

This method of compliance is similar to the design velocity alternative discussed above, except that the intake's maximum design velocity can exceed 0.5 fps, as long as the intake is operated such that the actual, measured velocity does not. As an example, a facility may have originally been constructed with a maximum design intake of 1.0 feet per second, but now, because it has retired generating capacity but not pumps, may only withdraw cooling water such that the actual intake velocity at the intake never exceeds 0.5 feet per second. This would constitute compliance with the impingement mortality standard. The maximum velocity must be achieved under all conditions, including during minimum ambient source water surface elevations (based on BPJ using hydrological data) and during periods of maximum head loss across the screens or other devices during normal operation of the intake structure.

Monitoring the velocity at the screen face or immediately adjacent to the screen face must be conducted at a minimum frequency of daily. Monitoring of the approach velocity does not meet this requirement. However, in lieu of velocity monitoring at the screen face, the owner or operator may calculate the through-screen velocity using intake water flow, water depth, and the screen open area. EPA is requiring this point of measurement to ensure that fish are actually able to swim away (not into an embayment from which they cannot escape) from the location within the intake structure at which they are most susceptible to being impinged.

Under today's final rule, the Director may authorize the facility to exceed the low velocity compliance alternative for brief periods for the purpose of maintaining the cooling water intake system, such as backwashing the screen face. In this compliance option, facilities are not subject to biological compliance monitoring unless otherwise specified by the Director (see § 125.96(c)).

4. Existing Offshore Velocity Cap

In this method of compliance, facilities will submit information under § 122.21(r) that they operate an offshore velocity cap that meets the definition at § 125.92(v) and that was installed prior to the effective date of this rule. The definition of offshore velocity cap includes the requirement that the velocity cap be located a minimum of 800 feet offshore. The velocity cap must include devices to exclude marine animals, such as bar screens. The velocity cap must be designed to change the direction of water withdraw from vertical to horizontal, thereby creating velocity patterns that can be sensed and trigger an avoidance response by fish and other aquatic organisms. Intake flow must be monitored at a minimum frequency of daily. This information will confirm the intended velocity patterns are created. In this compliance option, facilities are not subject to biological compliance monitoring

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unless otherwise specified by the Director (see § 125.96(c)).

EPA notes that facilities choosing to construct a velocity cap at an offshore location after the effective date of this rule would use compliance options § 125.94(c)(6) (Systems of Technologies as the Site-specific BTA for Impingement Mortality) or § 125.94(c)(7) (Impingement Mortality Performance Standard).

5. Modified Traveling Screens

In this method of compliance, a facility must first operate a modified traveling screen that meets the definition at § 125.92(s). The definition identifies and requires those features of a traveling water screen that provide for an appropriate level of fish protection: collection buckets (or equivalent) to minimize turbulence to aquatic life; guard rails or barriers to prevent loss of fish from the collection system; screen panel materials such as smooth woven mesh, drilled mesh, molded mesh, or similar materials to protect fish from descaling; continuous or near-continuous rotation of screens and operation of collection equipment to recover impinged fish as soon as practical; low pressure wash or vacuum to remove collected organisms from the screens; fish handling and return with sufficient water flow to return fish directly to the source water in a manner that does not promote predation or the re-impingement of the fish, or a large vertical drop. EPA intends for this definition to generally include modified Ristroph screens (including Geiger screens, Beaudrey WIP screens, and Hydrolox screens), dual flow screens, and rotary screens.

Modified traveling screens with a fish return and handling system is the technology basis for the impingement mortality standard, therefore the EPA fully expects biological monitoring of a properly designed, built, and operated modified traveling screen would consistently be able to meet the impingement mortality performance standard. If EPA were to simply set a performance standard based on the numeric performance levels achievable by modified traveling screens, a facility would have to conduct continual biological monitoring to demonstrate compliance. A far more efficient way to demonstrate compliance would be for facilities to optimize the operation of their technologies for their site-specific conditions and identify the conditions that distinguish proper operation at their facility. The optimized operation of the technology would be largely demonstrated through the biological data collection and studies required in the permit application at § 122.21(r)(4) and (6)(i), including an *impingement technology performance optimization study.* Biological data collection should follow the sampling protocols described in section7 below.

The optimized operation documented by the *impingement technology performance optimization study* will result in more than just meeting the impingement mortality standard, and results in a facility achieving the best possible performance.[93] The biological data collection and analysis in the *impingement technology performance optimization study* will identify the operating conditions that result in optimized performance, such as fish sluicing spray pressures, rotation speed and frequency of the screens, angle of the fish sluicing sprays, fish return trough water flows, and fish return trough location.[94] The Director will then establish these operating conditions as permit conditions, along with an equipment inspection condition to assure proper functioning of the technology. As long as the permit conditions are met, the EPA does not expect any biological compliance monitoring will be required, unless otherwise specified by the Director, for example, for the protection of shellfish or fragile species (see § 125.96(c)). Note that EPA does not intend for facilities to install closed-cycle cooling solely for the purpose of meeting the IM requirements.

6. Systems of Technologies as the BTA for Impingement Mortality

In this method of compliance, a facility must demonstrate a system of technologies is employed that will meet the impingement mortality standard. This option will allow a facility the flexibility to choose the systems approach of technologies, management practices, and operational measures it will use to demonstrate compliance, including but not limited to flow reductions, intake location, behavioral deterrents, unit closures, seasonal operations, and newly installed velocity caps. Like the compliance option for modified traveling screens, the optimized operation of the system of technologies will be largely demonstrated through the biological data collection and studies required in the permit application at § 122.21(r)(4) and (6)(ii). However, the analysis and studies for combining the performance of varied technologies is more involved.

If the system of technologies includes credit for reductions in the rate of impingement by the system, the *impingement technology performance optimization study* required at § 122.21(r)(6)(ii) will provide an estimate of those reductions including relevant supporting documentation. The estimated reductions in rate of impingement must be based on a comparison of the facility's system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody. EPA expects Phase II facilities will use information already collected as part of their *calculation baseline* (69 FR 41594, July 9, 2004). In addition, the study must include two years of biological data collection demonstrating the rate of impingement resulting from the system. For this demonstration, data collection must be conducted no less frequently than monthly. The Director may establish more frequent data collection or a longer period of study.

If the system of technologies includes credit for reductions in impingement mortality already obtained at the facility, the study must include two years of monthly biological data collection demonstrating the level of impingement mortality the optimized system achieves. Biological data collection must be representative of the impingement and the impingement mortality at the intakes and should follow the sampling protocols described in section 7 below. The *impingement technology performance optimization study* must provide a description of any sampling approach used in measuring impingement mortality, including a taxonomic identification to the lowest taxon possible of all organisms to be sampled; the method in which naturally moribund organisms are identified and taken into account; and the method in which mortality due to holding times is taken into account. In addition, the study must describe how the location of the cooling water intake structure in the waterbody and the water column are accounted for in the sampling locations. EPA requires the entrapment of organisms, as well as organisms that are carried over the screen, to be counted as impingement mortality.

If the system of technologies specifically includes flow reduction to reduce impingement, the *impingement*

[93] As demonstrated by the numerous studies included in the record for today's final rule, many facilities are able to achieve less than 10 percent impingement mortality, a performance level comparable to the impingement mortality of closed-cycle cooling. Merely requiring facilities to achieve a numerical performance standard through modified traveling screens creates disincentives to perform better.

[94] EPA also requires the entrapment of organisms, as well as organisms that are carried over the screens, to be counted as impingement mortality.

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technology performance optimization study must include two years of intake flows, measured daily, as part of the demonstration, and must describe the extent to which flow reductions are seasonal or intermittent. The rule clarifies that credit for flow reductions must result from actual reductions in flow, therefore the AIF will be used as a point of comparison, and not the DIF. The study must document how the flow reduction results in reduced impingement, and how the reduction in impingement has reduced the site-specific impingement mortality. Today's final rule at § 125.98(f)(3)(iii) further clarifies that credit in reduced impingement or impingement mortality resulting from unit closures will be valid for a period of 10 years.[95] This is also reflected in permit application requirements for an owner or operator planning to retire the facility in the current permit term at 40 CFR 122.21(r)(1)(ii)(F), or in the following permit cycle at 40 CFR 122.21(r)(1)(ii)(G).

The Director must determine the system of technologies, management practices, and operational measures that is the best technology available for impingement reduction at the site. As the basis for the Director's determination, the facility must demonstrate that the system of technology has been optimized to minimize impingement mortality of all non-fragile species. In addition to the *impingement technology performance optimization study,* the Director may also use the biological source water characterization and/or the entrainment characterization studies in the permit application. EPA expects the Director's decision will be informed by comparing the impingement mortality data under § 122.21(r)(6)(ii) to the impingement mortality performance standard that would otherwise apply under § 125.94(c)(7).

In addition, the *impingement technology performance optimization study* requires documentation of the percent impingement mortality reflecting optimized operation of the total system of technologies, operational measures, and best management practices and all supporting calculations. The following example illustrates how these provisions will adjust for flow, location, and other technologies in demonstrating the IM performance for a system of technologies.

The example uses values that simplify the calculations to better illustrate the adjustments, and are not intended to reflect values that EPA expects at any facility. To simplify the example further, the facility has only fish and does not have shellfish in its source waters. EPA has chosen a hypothetical facility that examined each change in a separate study.[96] The hypothetical facility intake is located at a submerged offshore location, has an acoustical deterrent, and installed variable speed drives. For the purposes of this example, the facility has completed sampling at the forebay for two years as part of § 122.21(r)(4) and (6). During the most recent 12 months, the counts of non-fragile species totals 40,000 impinged fish. During the 24-hour holding period following each monthly sample collection, the total fish that died were counted, for a total of 12,000 dead fish for the preceding 12 months. The facility then calculated the average IM for the preceding 12 months at 30 percent as follows:

$$\%\ IM = \frac{\text{(impinged fish that are killed)}}{\text{(total number of impinged fish)}} \times 100$$

$$= (12{,}000) / (40{,}000) \times 100$$
$$= 30\ \%$$

To adjust the observed percent IM for a submerged offshore location and acoustical deterrent, the facility first extracts information from its previously conducted studies related to performance and calculation baseline. Alternatively, the facility could conduct a performance study during the same two year period in which it conducts its biological data collection as part of the permit application requirements at § 122.21(r). For the submerged offshore location adjustment, fish density and flow data show the offshore location reduces the rate of impingement for all species by 4,000 fish annually. For the acoustical deterrent, performance data show a reduction in the rate of impingement of fish by 11,000 organisms annually. For purposes of this example, assume none of the 15,000 fish are assumed to contribute to further mortality; in other words, all of the fish that avoided impingement in the first place survive. Therefore, the facility has reduced impingement by 15,000 fish (*i.e.,* sum of both submerged offshore location and acoustical deterrent). The facility then takes credit for this reduction by adding the forgone impingement to the denominator of the percent IM calculations as follows:

$$\%\ IM = \frac{\text{(impinged fish that are killed)}}{\text{(total number of impinged fish)}} \times 100$$

$$= (12{,}000) / (40{,}000+15{,}000) \times 100$$
$$= 22\ \%$$

[95] Because a permit may be administratively continued or may not be issued every 5 years, EPA has specified 10 years rather than two permit cycles to avoid facilities from taking credit for a unit closure that potentially occurred decades prior.

[96] EPA recognizes that facilities often examine the combined effect of two or more technologies (e.g., deterrents and offshore location) within a single study. In applying these provisions, the facility could use the outcomes associated with the combined performance of multiple technologies, but this would result in permit conditions that would also be combined.

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In summary, calculating percent IM at the forebay yields a 30 percent IM, and then applying the performance for existing technologies shows the effective percent IM is actually 22 percent. Next, to adjust for the variable speed drives, the facility has determined from flow monitoring that the volume of cooling water flow has been reduced by 11 percent. In this example, assume the flow reduction does not vary considerably each month. The volume of reduced flow multiplied by the density of fish near the intake is calculated each month for 12 months, and the facility projects that the reduced flow excludes an additional 8,000 fish from impingement each year. Then the facility would apply the reduction in annual counts of impinged fish to the denominator, as follows:

$$\% \text{ IM} = \frac{\text{(impinged fish that are killed)}}{\text{(total number of impinged fish)}} \times 100$$

$$= (12{,}000) / (40{,}000+15{,}000+8{,}000) \times 100$$
$$= 19\%$$

Thus, the facility's site-specific system of technologies including optimized operation of acoustical deterrents has a total system performance of 19 percent annual impingement mortality. This example is intended to illustrate how facilities would obtain credit for existing technologies in a systems approach. While this example includes acoustical deterrents, it does not imply that acoustical deterrents are an appropriate technology for all facilities. EPA expects a facility will use the required two years' worth of monthly biological data collection and studies to conduct a similar analysis for each month. The minimum required data collection and studies will result in annual average performance calculations for 12 consecutive months. The facility will use this information as part of its demonstration to the Director.

If the Director determines the system of technologies, management practices, and operational measures is the best technology available for impingement reduction at the site, the Director will establish specific operating conditions as permit conditions, along with appropriate equipment inspection conditions to assure proper functioning of each technology. For example, a system with acoustical deterrents would likely have permit conditions related to frequency of tones, volume, location, and frequency of operation of the acoustical deterrents. The Director will also establish monitoring requirements for intake flow and velocity where such measures are an important part of the system of technologies, such as the case of variable speed drives. For example, a system that includes seasonal flow reductions would likely have permit conditions for flow monitoring. As long as the permit conditions are met, the EPA does not expect any biological compliance monitoring will be required, unless otherwise specified by the Director (see § 125.96(c)).

7. Impingement Mortality Performance Standard

In this method of compliance, facilities are required to monitor to demonstrate compliance with the impingement mortality performance standard at § 125.94(c)(7) by demonstrating a 12-month average mortality of 24 percent or less. The facility is required to monitor at a minimum frequency of monthly, unless a greater frequency is specified by the Director. For each monitoring event, the facility would determine the number of non-fragile organisms that are collected or retained on sieve with a maximum spacing of 0.56 inches (*i.e.,* that are impinged [I]), and the number that die after impingement (*i.e.,* impingement mortality [IM]). The facility must establish a post-impingement holding period of 18 to 96 hours otherwise specified by the Director. Under the definition at § 125.92(b), *all life stages of fish and shellfish* excludes specified nuisance species from the totals for both impingement and impingement mortality. Also, as defined at § 125.92(q), *latent mortality* means the delayed mortality of organisms that were initially alive upon being impinged or entrained but that do not survive the delayed effects of impingement and entrainment during an extended holding period. Delayed effects of impingement and entrainment may be due to stresses that include but are not limited to temperature change, physical stresses, and chemical stresses. The manner in which latent mortality is counted must be identified in the Entrainment Characterization Study at § 122.21(r)(9), and must also be counted in the *Impingement mortality performance standard* at § 125.94(c)(7). Fish that are included in any carryover from a traveling screen or removed from a screen as part of debris removal must be counted as impingement mortality. Fish that are entrapped by the cooling water intake system must be counted as impingement mortality.

The 12-month average of impingement mortality is calculated as the sum of total impingement mortality over 12 months divided by the sum of the total impingement over the same 12 months, as shown by the following equation:

$$\% IM = \left(\frac{IM}{I}\right) \times 100$$

Note that this equation would be applicable to calculating the annual average for the previous 12 months. Although facilities will be conducting biological monitoring monthly (or more frequently) and reporting that data in their discharge monitoring reports, facilities are not required to meet a monthly impingement mortality performance standard. Therefore, in this equation, *IM* is the sum of all impingement mortality over the course of the previous 12 months, and *I* is the sum of all impinged fish for the previous 12 months. If the facility's calculated annual average percentage impingement mortality is less than the 12-month average performance standard, it will be deemed to be in compliance with the 12-month average performance standard.

In establishing the monitoring requirements, EPA expects any approved monitoring protocols will

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consider the entire daily and (where appropriate) tidal cycles over which data collection should occur. Typically, facilities have collected impingement samples continuously for 6 or 8 hours and repeated this cycle to cover an entire 24-hour period. Stratifying collection in this manner allows an analysis of the diel variation exhibited by many aquatic organisms, which may be important. EPA also expects the approved monitoring protocols will ensure that sampling occurs during periods of representative intake flow and not during periods of non-peak flow or scheduled outages.

The ideal point to measure impingement mortality is the location where organisms are returned to the waterbody. However, for ease of sampling and access, EPA envisions that most facilities will collect samples from the fish return system(s) at some point before the fish return discharge point. According to the studies in EPA's database, EPA envisions that facilities will either (1) divert some or all of the flow from the fish return into a fish collection and holding area, or (2) place a net or basket fitted with 3/8-inch mesh spacing in the fish return and collect and transfer the retained organisms to a holding tank. While nearly all studies in the record report the use of 3/8-inch mesh spacing, as discussed below, the final rule allows the use of other sieve and mesh spacings with a 0.56 inch maximum opening. A facility will handle the organisms in the collection device as little as possible and transfer them to a holding area with conditions as close as practicable to the source water. The facility will count the number of organisms in the holding area and subsequently hold the sample using proper technique [97] to maintain the health of the collected organisms.[98] At a period of 18 to 96 hours after the initial collection, the facility will count the number of dead organisms and determine the percentage of organisms that died in comparison to the total number of organisms measured initially. Any organisms not collected by the fish handling and return system, such as entrapped organisms, organisms in the carryover of a traveling screen, or organisms collected by a high-pressure wash and sent to debris bins, will be counted as 100 percent impingement mortality. The facility will keep records of this information and compare its result to the impingement mortality performance standard at § 125.94(c)(7).

As explained in Section VI, the impingement mortality restrictions in the final rule are based on the operation of a modified traveling screen with a fish return. Because EPA wants to ensure that a facility's monitoring plan is consistent with the technical basis for today's requirements, EPA is requiring facilities to monitor impingement mortality using a sample that has been passed through a sieve or net with no more than 0.56 inches maximum opening, so that only organisms that do not pass through this mesh size are counted.[99] In doing so, facilities would retain (and therefore count) only organisms that would have been impinged on a 3/8″ mesh screen, which was the technological basis used for developing the impingement mortality performance standard.[100] Facilities could similarly apply a ''hypothetical net'' in that they could elect to count only organisms that would not have passed through a net with mesh openings less than 0.56 inches. For example, a facility that uses a fine-mesh screen of 0.5 mm or diverts the flow directly to a sampling bay will need to count only organisms that remain if the flow passed through a net, screen, or debris basket fitted with 3/8-inch mesh spacing. EPA further expects the impingement mortality restrictions could be applied to other fish protection technologies and provides a compliance route for future technologies that are better performing.

In today's rule, EPA is including provisions for reduced biological monitoring. EPA determined that monthly monitoring at a minimum is appropriate for at least the first full permit term. In permit terms subsequent to the first permit issued under today's rule, the owner or operator may request the Director to reduce monitoring requirements under § 125.95(c). EPA expects the Director would reduce monitoring requirements as appropriate, if the facility demonstrates that its operational and biological conditions have remained the same. Given that the source waterbody may change over time (including hosting different or increased numbers of individuals or species), the biological characterization required at § 122.21(r)(4) including two years of data serves to alert interested parties as to the status of the waterbody and any changes in the biology of the waterbody. Under the compliance option (7) impingement mortality performance standard, EPA expects that as new technologies are successfully demonstrated, in subsequent permits facilities would request less frequent monitoring, or be able to incorporate such technologies in a permit application choosing a § 125.94(c)(6), system of technologies, demonstration. Once the Director has determined the technology is fully demonstrated for that site, the facility would therefore reduce their biological data collection to the minimum required by the permit application at § 122.21(r) and any monitoring the Director determines to be appropriate for verifying permit operating conditions.

8. Additional Measures

Sections § 125.94(c)(8) and (9) provide the Director discretion to require additional measures to protect shellfish and fragile species. An example of shellfish protection measures is a barrier net, including seasonal deployment of such nets. An example of additional protection measures for fragile species is an acoustical deterrent system.

9. Summary

The following Exhibit VIII–4 summarizes the monitoring requirements for impingement mortality by compliance approach alternative. The Director has the discretion to require additional monitoring under § 125.96(c) and (d). Since all permits must have requirements for visual inspections, these are not included in the exhibit.

[97] EPA recognizes that at present, there are no standard methods for conducting impingement and entrainment studies and that there can be variability in designing a sampling plan between sites. However, some elements should be incorporated into any sampling plan, as outlined in DCN 10–6708.

[98] Facilities that divert the flow directly would similarly pass the flow through a net or debris basket fitted with 3/8-inch mesh spacing or would count only organisms that would have been collected with such a basket or net.

[99] For a discussion of how EPA has changed its view of screen mesh size, see Section III of the proposed rule (76 FR 22188, April 20, 2011). EPA recognizes that smaller organisms that previously would have passed through a screen and been entrained might be ''converted'' by a fine mesh screen to an impinged organism; because organisms size would affect the rate of mortality, EPA has chosen not to rely on definitions of impingement and entrainment based on a physical process, but instead to define impingement mortality and entrainment mortality based on organisms sizes.

[100] EPA's analysis of impingement survival rates is based on data from facilities with 3/8″ mesh screens; the performance standard may be applied differently at facilities with smaller mesh size. Therefore, these standards do not provide a disincentive to facilities from using finer-meshed screens (i.e., screens with a mesh opening smaller than 3/8 inch) on their traveling screens. As long as the organisms that are large enough to have been impinged on a coarse mesh screen achieve the required survival rates, the facility will be considered to meet the impingement mortality requirements.

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EXHIBIT VIII–4—SUMMARY OF MONITORING REQUIREMENTS FOR IMPINGEMENT MORTALITY

Compliance approach	Type of monitoring	Frequency
Closed-cycle recirculating system	Intake, makeup and blowdown flows (or cycles of concentration)	Daily.
Velocity (DIF)	None	None.
Velocity (AIF)	Velocity (measured or calculated from flow)	Daily.
Velocity cap	Intake flow	Daily.
Modified traveling screens	TBD [a]	TBD [a].
Systems of Technologies	TBD [b]	TBD [b].
Impingement mortality performance standard	Biological monitoring	Monthly.

[a] Monitoring requirements may vary, depending on the permit-specific operating conditions.
[b] The monitoring requirements are based on the technologies employed. For example, seasonal flow reduction would require flow monitoring.

G. What monitoring is required for entrainment?

Where the Director establishes entrainment controls, the Director is required to establish monitoring requirements. The final rule requires that the permit application studies at § 122.21(r) be submitted for each permit renewal. For facilities that withdraw 125 mgd AIF, EPA expects that the Director will use these studies, including the Source Water Baseline Biological Characterization Data at § 122.21(r)(4) and the Entrainment Characterization Study at § 122.21(r)(9), as a basis for any monitoring requirements for entrainment. To facilitate the determination of entrainment requirements for facilities below 125 mgd AIF, a Director may require the owner or operator to submit some or all of the study requirements at § 122.21(r)(9) through (13) or variations thereof. The Director may require additional monitoring necessary to demonstrate compliance with § 125.94(d), additional measures to protect Federally-listed endangered and threatened species and designated critical habitat requirements under § 125.94(g), interim standards under § 125.94(h), and any more stringent standards under § 125.94(i).

Under § 125.96(d), existing facilities with new units are required to conduct compliance monitoring to demonstrate flow reductions consistent with the requirements of § 125.94(e)(1), or equivalent impingement and entrainment reductions. The Director may establish flow monitoring or monitoring of cycles of concentration as discussed in Section F. Such measures will be used to document that the facility has minimized make-up and blowdown flows.

For facilities complying under § 125.94(e)(2), the frequency of monitoring will be determined by the Director and will vary depending on the facility's chosen method of compliance.

To meet requirements under § 125.94(e)(2), facilities must measure AIF to establish a site-specific baseline without any new technologies or employing additional operational measures. The facility must also measure the density of entrainable organisms (E_D) at a proximity to the intake that is representative of the entrainable organisms present without the cooling water intake structure. Samples will be collected over a 24-hour period to monitor each species as required by the Director. Samples will be collected no less than biweekly during the primary period of reproduction, larval recruitment, and peak abundance identified during the Source Water Baseline Biological Characterization Data required under § 122.21(r)(4). Samples will be representative of the cooling water intake when the structure is in operation. In addition, sufficient samples must be collected to allow for calculation of 12-month average entrainment levels. The sampling will measure the total count of entrainable organisms or density of organisms, unless the Director approves of a different metric for such measurements. If the abundance varies seasonally, the Director may require several measurements of entrainment through the year, from which a 12-month average can be calculated.

For the purpose of today's rule, *entrainable* is defined as any organism that passes through a sieve with a maximum opening of 0.56 inches. As discussed in Section VI, this would avoid any confusion as to which organisms are subject to which standards (i.e., requirements for IM or requirements for E). The regulation specifies that the sieve used for calculating impingement must be the same sieve used for calculating entrainment, so all organisms are accounted for. Facilities can also monitor the latent entrainment mortality in front of the intake structure. Entrainable organisms passing through the cooling water intake structure are to be counted as 100 percent entrainment mortality unless the facility demonstrates to the approval of the Director that the mortality for each species is less than 100 percent.

In addition, facilities must monitor the AIF for each intake. The AIF must be measured at the same time as the samples of entrainable organisms are collected.

The following equation illustrates how to calculate a baseline level of entrainment (E_B):

$$E_B = E_D \times AIF$$

Performance commensurate with a closed-cycle recirculating system (E_{CCRS}) can therefore be determined by reducing E_B by the percentage of flow reduced through the use of a closed-cycle cooling system. For example, a facility withdrawing make-up water from a freshwater source (as described above, would achieve a reduction of 97.5 percent) will calculate its performance as follows:

$$E_{CCRS} = (E_B) \times (100 - 97.5) \div 100$$

The resulting value, E_{CCRS}, is the required level of entrainment performance (as measured by entrainment mortality). The facility could implement any combination of flow reduction, technologies, and operational measures to meet the required level of entrainment performance. For example, a facility withdraws 200 mgd AIF from a freshwater river. The annual average entrainment density in the proximity of the intake structure is 6,400 organisms per 100 cubic meters withdrawn.

$$E_B = E_D \times AIF$$

$$6{,}400 \text{ organisms}/100\text{m}^3 \times (100\text{m}^3/26{,}417 \text{ gallons}) \times 200{,}000{,}000 \text{ gallons per day}$$

$$= 48 \times 10^6 \text{ organisms per day}$$

The maximum entrainment mortality for a closed-cycle cooling system is thus

$$E_{CCRS} = (E_B) \times (100 - 97.5) \div 100$$

$$= (48 \times 10^6 \text{ organisms per day}) \times (100 - 97.5) \div 100$$

$$= 1.2 \times 10^6 \text{ organisms per day.}$$

The minimum required level of performance for demonstrating entrainment mortality at a comparable level (E_C) to a closed-cycle cooling system is the level corresponding to 90

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percent [101] of the reduction that a facility with a closed-cycle cooling system could achieve:

$E_C = (E_B) \times (100 - (97.5 \times .9)) \div 100$
$= (48 \times 10^6$ organisms per day$) \times (100 - (97.5 \times .9)) \div 100$
$= 5.88 \times 10^6$ organisms per day.

The Director may require additional monitoring necessary to demonstrate compliance with § 125.94(d), endangered species requirements under § 125.94(g), interim standards under § 125.94(h), and any more stringent standards under § 125.94(i).

In addition, all facilities will either conduct visual inspections or employ remote monitoring devices when the cooling water intake structure is in operation. The facility will conduct such inspections at least weekly to ensure that any technologies installed to comply with § 125.94 are maintained and operated to ensure that they will continue to function as designed. EPA is aware that for some facilities, this requirement could pose a feasibility challenge (for example due to ice cover in the winter season, inability of divers to see through more than a few inches of water, or certain intakes in deep water). The rule, therefore, authorizes the Director to establish alternative procedures. See § 125.96(e).

H. What reports am I required to submit?

1. Status Reports

If the Director establishes a compliance schedule, the Director will also establish any status reporting requirements. These reports may include updates on biological monitoring, technology testing results, construction schedules, or other appropriate topics and serve as milestones for the facility and the Director to evaluate the progress of the facility in meeting BTA. See §§ 125.94(b) and (d) and 125.97(b).

2. Monitoring Reports

The required reports for monitoring activities are similar to requirements that are already in NPDES permits for effluent discharges. EPA expects such reports to be included with the Discharge Monitoring Reports (DMRs) or equivalent state reports. Facilities would report any monitoring, demonstration, and other information required by the permit sufficient to determine compliance with the permit requirements established under § 125.94, as well as any other monitoring requirements specified in the permit. See 40 CFR 125.97(a).

Entrainment requirements will be determined on a site-specific basis by the Director. For facilities that are required to install entrainment controls, EPA expects that these facilities would generally conduct ongoing flow (or other) monitoring as verification that entrainment has been reduced. See § 125.96(b) and (c). However, the Director may require facilities to report entrainment monitoring and analysis, including:

- The compliance measurement location.
- A description of the flow monitoring procedure.
- Documentation of flow reductions.
- Any other monitoring requirements specified in the permit.

The report must include any monitoring and analysis required as part of additional measures for threatened and endangered species, shellfish, or fragile species as established by the Director. Further, your report will include documentation of cooling water that is process water, gray water, waste water, reclaimed water, or other water reused as cooling water in lieu of water obtained by an intake. The Director will evaluate these reports for compliance with permit requirements as appropriate.

3. Annual Certifications

Today's rule requires a facility to submit an annual certification statement signed by the responsible corporate officer. See § 125.97(c). In most cases, the statement would indicate the information from the previous statement is still pertinent. If modifications were made to the facility that impacts cooling water withdrawals or operation of the cooling water intake structures, the statement would indicate such, and the facility would submit revisions to the information required in their permit application at § 122.21(r).

4. Other Reporting

In addition, EPA notes that supplemental reporting may be required under the ESA as part of any incidental take statement or permit (50 CFR 402.14(i)) or a section 10 permit (50 CFR 222.307) that is issued by the United States Fish and Wildlife Service or the National Marine Fisheries Service to ensure compliance with the Endangered Species Act.

I. What records will I be required to keep?

As described at § 125.97(d), facilities are required to keep all permit applications, status, monitoring, and annual reports and related supporting information and materials at least until the subsequent permit is issued. Facilities might wish to keep records for a longer period to maintain a complete regulatory history of the facility. For example, existing source water biological studies submitted with a facility's permit application could contain data that has been collected in the past 10 or more years. When the Director has approved a request for reduced information collection in the permit application, the rule requires that records of submissions that are part of a previous permit application be kept until the subsequent permit is issued. See § 125.95(e). Records supporting the BTA determination for entrainment must be kept until such time as the Director revises the determination. The Director may establish additional record-keeping requirements in the permit, such as additional records documenting compliance monitoring, data collection, or more frequent reports.

Facilities must also keep records of all data used to complete the permit application and show compliance with the requirements of § 125.94, any supplemental information developed under § 125.95, and any compliance monitoring data submitted under § 125.96. The Director may require that these records be kept for a longer period.

J. What are the respective Federal, State, and Tribal roles?

Today's final rule affects authorized State and Tribal NPDES permit programs. Under 40 CFR 123.62(e), any existing approved section 402 permitting program must be revised to be consistent with new program requirements within one year from the date of this promulgation, unless the NPDES-authorized State or Tribe must amend or enact a statute to make the required revisions. If a State or Tribe must amend or enact a statute to conform to today's final rule, the revision must be made within two years of this promulgation. States and Tribes seeking new EPA authorization to implement the NPDES program must comply with the requirements when authorization is approved. This final regulation does not alter State authority under section 510 of the CWA.

In addition to updating their programs to be consistent with today's final rule,

[101] The 90 percent metric is required in Phase I, and adopted here because new units are subject to requirements similar to the Phase I requirements. Phase I, at 40 CFR 125.86 specifies, ''reduced both impingement mortality and entrainment of all life stages of fish and shellfish to 90 percent or greater of the reduction that would be achieved through § 125.84(b)(1) and (2).''

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States and Tribes authorized to implement the NPDES program are required under NPDES State program requirements to implement the cooling water intake structure requirements of subpart J following promulgation of the final regulations. The permit requirements in this final rule must be implemented upon the first issuance or reissuance of permits following promulgation. Duties of an authorized State or Tribe under this regulation are described throughout this section and include reviewing permit application materials, determining appropriate requirements, reviewing monitoring and reporting data, and assessing whether a facility is complying with the final rule's requirements.

EPA recognizes that some States have invested considerable effort in developing and implementing section 316(b) permits. This final regulation at § 125.98(b) and (g) allows the Director flexibility where there are ongoing permit proceedings or where a BTA determination has already been made based on substantially the same information required at § 122.21(r).

EPA will implement these requirements where States or Tribes are not authorized to implement the NPDES program.

K. Protection of Endangered and Threatened Species and Designated Critical Habitat

1. Existing Requirements Under Section 9 of the Endangered Species Act

The ESA imposes duties not just on Federal agencies but also on other entities. Section 9 of the ESA specifically provides that it is unlawful for any person to ''take'' any endangered species of fish or wildlife except under defined circumstances. The Services (National Marine Fisheries Service or U.S. Fish and Wildlife Service) may provide an exemption to the prohibition on take in one of two ways. Take may be permitted under section 10 of the ESA (16 U.S.C. 1539) or the Services may provide an exemption for take that is incidental to otherwise legal activity through a statement that is included with the Services' biological opinion developed during Federal agency consultation. (16 U.S.C. 1536(o)) The incidental take statement specifies the terms and conditions necessary to implement reasonable and prudent measures which minimize incidental take.

Nothing in today's rule changes the existing, independent obligations of the facilities subject to this rule under section 9 of the ESA. Unless exempted by an incidental take statement or section 10 permit, facilities have been prohibited from taking (for example, harming or killing) endangered species of fish or wildlife. In order to obtain a section 10 permit, the facility would be required to develop a Habitat Conservation Plan (HCP), which is a mandatory component of an incidental take permit application. The HCP must specify the anticipated effects of the proposed taking, how those impacts will be minimized or mitigated, the alternative actions to the taking that the applicant considered, the reasons for not utilizing those alternatives, and other necessary or appropriate measures that the Secretary may require.

2. EPA's Consultation Under Section 7 of the ESA

Under section 7 of the Endangered Species Act, each Federal agency must insure that any action authorized, funded, or carried out by the agency ''is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined by the Secretary, after consultation as appropriate with affected States, to be critical. . . .'' 16 U.S.C. 1535(a)(2). In the case of any Federal agency action subject to the ESA that may affect listed species or critical habitat, the Federal agency must consult with the concerned offices with responsibilities under the ESA, specifically NMFS and/or FWS. 50 CFR 402.14(a).

In July 2012, EPA began informal consultation with the NMFS about the proposed section 316(b) regulations. In October 2012, EPA began informal consultation with the FWS. EPA prepared a draft biological evaluation of the effects of this rule on threatened and endangered species and in it concluded that the rule was not likely to adversely affect listed species or designated critical habitat. EPA was unable to obtain the Services' concurrence on EPA's ''not likely to adversely affect'' finding. In June 2013, EPA requested formal consultation with the Services under the Endangered Species Act and with that request submitted a final biological evaluation to the Services. EPA completed consultations with the Services and has included the Services' biological opinion and associated documents in the record for this rulemaking.

Among the organisms potentially subject to impingement and entrainment at cooling water intake structures are those that are listed as threatened and endangered. In addition to impinging or entraining threatened and endangered species, operation of CWISs may also adversely affect their critical habitat. Today's rule includes a number of provisions specifically designed to address incidental take of all federally-listed threatened and endangered species and to insure that the rule is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of critical habitat. These provisions are described below.

The regulatory model adopted by EPA in the Phase I rule and later in the subsequently-withdrawn Phase II rule for large existing power producing facilities provided a structure to address and minimize adverse impacts to threatened and endangered species. EPA's approach required that facilities subject to the 316(b) rules, at the permit application stage of the permitting process must, among other things, identify threatened and endangered species that might be subject to impingement and entrainment in order to ensure that the permitting authority would have the requisite information on which to make a decision about the need for controls to protect threatened and endangered species. See 40 CFR 122.21(r)(4).

The Phase I and Phase II regulations specifically authorized the permit writer (referred to as the ''Director'' in EPA's permitting regulations) to adopt measures designed to protect threatened and endangered species. Thus, for example, EPA's Phase I regulations for cooling water intake structures at new facilities require that, under one of the compliance options, an owner or operator must select and implement impingement and entrainment minimization measures ''if there are threatened or endangered or otherwise protected Federal, State or Tribal species.'' Moreover, the permit writer may require additional impingement and entrainment reduction measures if the permit writer determines that the facility after meeting the required performance standard would ''still contribute unacceptable stress to the protected species, critical habitat of those species or species of concern.'' 40 CFR 125.84(b)(4) & (5).

The Phase II regulation continued the general approach followed in the Phase I regulation for protection of threatened and endangered species. Permit applicants needed to submit the same information on threatened and endangered species required in the Phase I rule. In addition, building on the earlier information requirements, the regulation also would have required facilities selecting and implementing certain of the alternative BTA

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compliance measures to submit a Comprehensive Demonstration Study that, among other things, characterized impingement and entrainment at the facility. Further, the rule would have required a facility to submit an Impingement Mortality and/or Entrainment Characterization Study that included taxonomic identification, characterization and documentation of current impingement mortality and entrainment of all life stages of fish, shellfish and any species protected under Federal, State or Tribal law (including threatened or endangered species). 69 FR 41687–88, July 9, 2004. In addition, the Phase I and II rules included a requirement for the facility to include in their permit application documentation of any public participation or consultation with Federal or State agencies on impacts of their cooling water intake structure on threatened and endangered species. The regulation then would have required the permit writer to determine appropriate permit requirements and conditions. EPA noted that its existing NPDES permitting regulations reference a number of Federal laws that might apply to Federally-issued NPDES permits, including the Endangered Species Act. 69 FR 41643–44, July 9, 2004.

Threatened and endangered species were important considerations in the proposal to today's rule and were of particular concern to the EPA. The preamble to the proposal reflects at a number of points that, in looking at the benefits of different regulatory options, EPA attempted to assess the benefits to threatened and endangered species. See 76 FR 22174, 22197, 22207. The proposal also noted the importance of obtaining information for the permit writer about potential entrainment reductions. Thus, the proposal would have required certain facilities to develop and submit with their permit application detailed information on their operations as well as an engineering study of the technical feasibility and incremental costs of candidate entrainment mortality control technologies and a detailed discussion of the magnitude of non-water quality benefits. EPA proposed that some facilities would need to submit an Entrainment Characterization Study that included an entrainment mortality data collection plan that would indicate, at a minimum, taxonomic identification, latent mortality identification, documentation of all methods, and quality assurance/quality control procedures or sampling and data analysis appropriate for a quantitative survey. Under the proposal, EPA would also have required peer review of the entrainment mortality data collection plan. Peer reviewers would be selected in consultation with the Director who may consult with EPA and Federal, State, and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure(s). Further, facilities with greater than 125 mgd AIF would complete an entrainment study. The entrainment study could include information already collected to meet the Phase II requirements at § 122.21(r)(2)–(r)(4) before those requirements were suspended.

EPA and the Services have completed consultations on the rule. EPA has received the final biological opinion and associated documents from the U.S. Fish and Wildlife Service and the U.S. National Marine Fisheries Service and has included them in the record for the rule. The Services have concluded that the rule is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat.

3. Final Rule Provisions Related to Threatened and Endangered Species

As noted previously, establishing standards for cooling water intake structures to minimize impingement and entrainment of all aquatic organisms will promote and enhance protection of T&E species. In addition, the rule contains a number of provisions that specifically concern T&E species; these provisions were developed in light of EPA's consultation with the Services and were established by EPA to insure that this rule is not likely to jeopardize listed species or result in the destruction or adverse modification of designated critical habitat. To be clear, the ESA provisions of the rule extend to all listed T&E species, not just fish and shellfish.

The treatment of T&E species in today's rule follows directly from the Agency's longstanding approach as well as from EPA's proposed 2011 rule which indicated the EPA's intention to address protection of T&E species. The rule adopts the identical approach followed in the Phase I and II rules, while adding some refinements to that earlier model which EPA discussed in the proposed rule. First, it adopts the proposed requirements that insure an adequate information base is submitted to the permit writer. As was the case with the Phase I and withdrawn Phase II rule, apprising the permit writer of the presence and extent of T&E species at a facility's intake continues to be an important element of the permit application requirements for existing facilities. While retaining the existing permit application requirement of 40 CFR 122.21(r), EPA has included in today's rule a provision at § 125.95(f) that requires a facility in its permit application to identify all Federally-listed threatened and endangered species and designated critical habitat that are or may be present in the action area. The action area can generally be considered the area in the vicinity of the cooling water intake structure. The evaluation is to be based on information readily available to the facility at the time of the permit application. In addition, the rule requires the largest withdrawing facilities to provide taxonomic identification of species in the vicinity of the intake, thus providing a mechanism for facilities to determine more accurately their potential impact on protected species.

The rule requires that the Director transmit all permit applications to the Services upon receipt. The rule provides the Services with 60 days to review the permit application. This 60 day review takes place prior to the public notice of the State or Tribe's draft or proposed permit. EPA expects that the Services will respond within 60 days and provide to the Director (1) any corrections to the list of Federally-listed threatened and endangered species and critical habitat included in the permit application, (2) any measures that the Services recommend (including monitoring and reporting) for the protection of listed species, including any measures that would minimize any incidental take of listed species, and/or avoid likely jeopardy to a listed species or destruction or adverse modification of critical habitat, and/or (3) notify the State or Tribe that the Service(s) have no corrections to the list of species and critical habitat and/or that the Service(s) do not recommend any control measures. The Services' 60 day review period does not constrain the Director's ability to process the applicant's permit application; however, the Director may not propose/publish the draft permit until the 60 day review period has ended, unless the Director has received the Services' response prior to that time.

In addition, the Services will receive, pursuant to existing regulations at 40 CFR 124.10(c)(1)(iii) and (e), all permit applications, as well as fact sheets or statements of basis (for EPA-issued permits), draft permits, and public notices for all permits. At this stage of the process, the Services will have the opportunity to review the draft permit and other materials and provide any

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additional input or suggested control measures to address effects to listed species or critical habitat. Together, the existing and new requirements related to transmittal of permitting documents to the Services will ensure that the Services have the opportunity to provide information and recommendations to the permit writer relating to any facility that may affect listed species. This information will be part of the public record for the permitting decision and the Director would be required to consider it as a relevant factor, along with all of the other relevant factors, in deciding what conditions to establish in the permit. Further, as explained in the MOA between EPA and the Services discussed elsewhere in today's notice, EPA will use the full extent of its CWA authority to object to a permit where EPA finds that issuance of the permit is likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat. The rule's requirements insure a full vetting of information and concerns in the permitting process that must be considered by the Director. These requirements, coupled with the EPA's commitment to exercise its oversight authority, insure that today's rule is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat.

Among the recommendations that may be made by the Services to the facility and the Director are measures to minimize incidental take. EPA expects that any measures the Services recommend to minimize incidental take will be consistent with ESA regulations and guidances concerning reasonable and prudent measures. As stated in the ESA regulations under 50 CFR 402.14(i)(2), ''Reasonable and prudent measures, along with the terms and conditions that implement them, cannot alter the basic design, location, scope, duration, or timing of the action and may involve only minor changes.'' The Endangered Species Handbook (FWS and NMFS, 1998) explains that: ''Measures are considered reasonable and prudent when they are consistent with the proposed action's basic design (e.g., narrowing of disturbed right-of-way at known species locations), location (e.g., temporary storage of equipment or other materials), scope, duration, and timing. Reasonable and prudent measures and terms and conditions should be developed in coordination with the action agency and applicant, if any, to ensure that the measures are reasonable, that they cause only minor changes to the project, and that they are within the legal authority and jurisdiction of the agency or applicant to carry out.''

Installation of closed-cycle cooling is a major design alteration of a facility involving significant design and construction activities (the range of costs associated with closed-cycle cooling is described elsewhere in today's notice). Because installation of closed-cycle cooling does alter the basic design of a facility and would involve more than minor changes, as described in the Services' regulations and Handbook, EPA does not expect that installation of closed-cycle cooling would be specified as a measure solely for purposes of minimizing incidental take. The final rule at § 125.98(j) provides that nothing in this rule authorizes the take of threatened or endangered species of fish or wildlife. However, the Services may exempt take through an incidental take statement issued pursuant to ESA section 7(o) or a permit under ESA section 10. See 16 U.S.C. 1536 (o) and 16 U.S.C. 1539.

This Clean Water Act rule cannot authorize take and does not purport to do so (nor can NPDES permits authorize take prohibited under the ESA). Accordingly, under § 125.98(b)(1), the permit writer, including EPA, must include, in the 316(b) permit requirements, standard language that states the permit does not authorize the take of Federally-listed threatened and endangered species. In addition, under § 125.96(g) (additional monitoring requirements) and § 125.97(g) (additional reporting requirements),where the Director requires additional measures to protect listed species, monitoring and reporting requirements associated with those measures will be included in the permit.

4. EPA Oversight of State-Issued NPDES Permits To Protect Threatened and Endangered Species

In 2001, the EPA, FWS, and NMFS signed a Memorandum of Agreement (MOA), (66 FR 11202, Feb. 22, 2001) with the objective of enhancing coordination between the agencies and to assist the agencies in executing their respective responsibilities under the Clean Water Act and Endangered Species Act. The MOA reflects, in part, the EPA's longstanding commitment to overseeing the operation of state NPDES programs to ensure protection of endangered species with existing regulatory requirements. The EPA reaffirms its commitment to ensure coordination of the EPA's and Services' programs and appropriate protection of listed species, and EPA will follow the procedures in the MOA in overseeing implementation of this rule.

The MOA committed the EPA to a number of specific actions that are pertinent to today's rule. Under the MOA, EPA committed, when contacted by the Services, to coordinate with the Services and the State/Tribe during the permit development process, in order to ensure that permits will comply with all applicable CWA requirements. One way in which coordination between EPA and the Services is facilitated is through the exchange of information about permits. The MOA facilitates such information exchange, as do EPA's NPDES permit regulations at 40 CFR 124.10, that preceded the MOA. These regulations require the Director to provide public notice and a comment period for draft permits, and to notify persons identified at 40 CFR 124.10(c)(1)(iii) and (iv). Such persons specifically include Federal and State agencies with jurisdiction over fish, shellfish, and wildlife resource and over coastal zone management plans and thus include the U.S. Fish and Wildlife Service and the National Marine Fisheries Service.

EPA's commitment to coordinate effectively with the Services includes following the procedures in section IX.A.6 and 7 of the MOA:

EPA may make a formal objection, where consistent with its CWA authority, or take other appropriate action, where EPA finds that a State or Tribal NPDES permit will likely have more than minor detrimental effect on Federally-listed species or critical habitat.

For those NPDES permits with detrimental effects on Federally-listed species or critical habitat that are minor, it is the intention of the Services and EPA that the Services will work with the State or Tribe to reduce the detrimental effects stemming from the permit. For those NPDES permits that have detrimental effects on Federally-listed species or critical habitat that are more than minor, including circumstances where the discharge fails to ensure the protection and propagation of fish, shellfish and wildlife, and where the State or Tribe and the Services are unable to resolve the issues, it is the intention of the Services and EPA that EPA would work with the State or Tribe to remove or reduce the detrimental impacts of the permit, including, in appropriate cases, by objecting to and Federalizing the permit where consistent with EPA's CWA authority.

EPA will use the full extent of its CWA authority to object to a State or Tribal permit where EPA finds (taking

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into account all available information, including any analysis conducted by the Services) that a State or Tribal permit is likely to jeopardize the continued existence of any listed species or result in the destruction or adverse modification of critical habitat.

EPA may review or waive review of draft State or Tribal NPDES permits (40 CFR 123.24(d)). EPA will work with the Services through the local/regional coordinating teams to help determine which categories of permits should be reviewed for endangered species concerns. If EPA finds that a draft permit has a reasonable potential to have more than a minor detrimental effect on listed species or critical habitat, and review of a draft permit has been waived, EPA will withdraw this waiver during the public comment period (see 40 CFR 123.24(e)(1)).

The grounds for EPA's exercise of its discretionary authority to object to State or Tribal permits are described in the NPDES regulations at 40 CFR 123.44. These include that the proposed permit fails to comply, or to ensure compliance with, any applicable requirement of this part, for example, that a permit application did not contain information sufficient to demonstrate that the permit will ensure compliance with applicable requirements. See 40 CFR 123.44(c)(1).

If EPA objects to a NPDES permit under the MOA, EPA will follow the permit objection procedures outlined in 40 CFR 123.44 and coordinate with the Services in seeking to have the State or Tribe revise its permit. A State or Tribe may not issue a permit over an outstanding EPA objection. If EPA assumes permit issuing authority for a NPDES permit, EPA will consult with the Service prior to issuance of the permit (as a Federal action) as appropriate under section 7 of the ESA.

While the MOA was adopted by the agencies in the context of NPDES permits for discharges of pollutants, it applies equally to NPDES permits that contain conditions for cooling water intake structures. Moreover, section 316(b) of the CWA accords EPA broad authority to protect waters of the United States from adverse environmental impacts associated with cooling water intake structures, including adverse effects to Federally-listed species and designated critical habitat. In implementing this provision, EPA is authorized to consider costs and benefits of different approaches to minimizing these impacts. The importance of listed species, and accordingly the benefits associated with preventing their extinction, animated Congress's enactment of the Endangered Species Act in 1973. In the case of aquatic organisms that are listed as endangered or threatened, and designated critical habitat, EPA has the authority, and will exercise the full extent of its authority, to object to a permit proposed by a State where EPA finds (taking into account all available information, and giving, as appropriate, substantial weight to the views of the Services) that a State or Tribal permit is likely to jeopardize the continued existence of such species or result in the destruction or adverse modification of such critical habitat. If the State permit is not modified to address EPA's objections, EPA will issue the permit in consultation with the Services. EPA's commitment to use the full extent of its CWA authority to object to permits that are likely to jeopardize listed species or result in the destruction or adverse modification of critical habitat is a safeguard for the protection of listed species and critical habitat. Additionally, where the Service communicates in writing to EPA its conclusion that a proposed State permit is likely to jeopardize the continued existence of a listed species, EPA will, upon request, provide the Service a written response. EPA's commitment to use the full extent of its CWA authority, along with the other provisions of the rule requiring the EPA, the Services, and State Directors to fully consider effects to threatened and endangered species and critical habitat and include appropriate protections in NPDES permits, insures that the rule is not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat.

L. Permits for Existing Facilities Are Subject to Requirements Under Other Federal Statutes

EPA's NPDES permitting regulations at § 122.49 list Federal laws that might apply to the issuance of NPDES permits under the NPDES rules. These include the Wild and Scenic Rivers Act, 16 U.S.C. 1273 *et seq.;* the National Historic Preservation Act of 1966, 16 U.S.C. 470 *et seq.;* the Coastal Zone Management Act, 16 U.S.C. 1451 *et seq.;* and the National Environmental Policy Act, 42 U.S.C. 4321 *et seq.* For a brief description of each of these laws, see § 122.49. The provisions of the Magnuson-Stevens Fishery Conservation and Management Act, 16 U.S.C. 1801 *et seq.,* relating to essential fish habitat might also be relevant. EPA's permit application requirements ensure that FWS and NMFS will have—and other Federal agencies as well, should have—a broader information base from which to make informed decisions. Note also that, in the case of EPA-issued permits, EPA's NPDES permitting regulations specifically require following the requirements of specific Federal laws that may apply to the issuance of NPDES permits.

IX. Cost Development and Economic Impact Analysis

This section summarizes EPA's analysis of the social cost and economic impact for three regulatory options. In addition to today's rule, referred to as the Final Rule, EPA analyzed two other options similar to those options at proposal (see section VI.D Other Options Considered for Today's Final Regulation for more context). The regulatory options can be described as follows:

- Final Rule: Flexible impingement mortality performance standard for existing units based on modified traveling screens with fish returns for all facilities with DIF greater than 2 mgd, closed-cycle cooling or its equivalent for new units for impingement and entrainment, and a national BTA standard that requires a site determination of entrainment BTA for all other existing units at existing facilities;
- Proposal Option 2: Intake flow commensurate with closed-cycle cooling for facilities that have a design intake flow of greater than 125 mgd, flexible impingement mortality limitations based on modified traveling screens with fish returns for all facilities with DIF greater than 2 mgd, and closed-cycle cooling or its equivalent for new units; and
- Proposal Option 4: Flexible impingement mortality limitations based on modified traveling screens for all facilities with DIF greater than 50 mgd, closed-cycle cooling or its equivalent for new units, and a site-specific determination of entrainment BTA for all other facilities and for impingement mortality controls at facilities with flow less than or equal to 50 mgd.

The first part of this section provides an overall summary of the costs of the regulatory options to regulated facilities and Federal and State governments. This discussion is followed by a review of the method for developing compliance cost estimates. The third part provides an estimate of the total social costs of the regulatory options. The final part reviews the economic impact of the regulatory options.

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A. Overview of Costs to Regulated Facilities and Federal and State Governments

In estimating the total cost of the regulatory options, EPA estimated costs for the following components: capital costs and other one-time costs; installation downtime costs; annual operation and maintenance costs; and recordkeeping, monitoring, entrainment-related studies, and reporting costs. All of these costs are included in the economic impact analysis for the final rule. The cost estimates reflect the incremental costs attributed only to this final rule. For example, facilities already having closed-cycle recirculating systems as defined at § 125.92 will meet the impingement mortality and entrainment standards of today's rule and, therefore, will not incur costs to retrofit new technologies. These facilities, including those in New York and California, will still incur permitting costs. EPA has established that existing closed-cycle recirculating systems will comply with the impingement BTA requirements.

For the economic analysis, EPA distinguished between the two industry groups regulated by the standards for existing facilities as follows:

- Electric Power Producers (electric generators)—facilities owned by investor-owned utilities, municipalities, States, Federal authorities, cooperatives, and nonutilities, whose primary business is electric power generation or related electric power services.
- Manufacturing and Other Industries (manufacturers)—facilities in the paper, aluminum, steel, chemicals, petroleum, food and kindred products (primary manufacturing industries), and other industries. In addition to engaging in production activities, some of these facilities also generate electricity for their own use and occasionally produce excess power for sale.

For a more detailed discussion of costs to regulated facilities and costs to Federal, State, and local governments, see Chapter 8 of the TDD and Chapter 3 of the EA.

Electric generators incurring costs include facilities owned by private firms, governments, and electric cooperatives. Manufacturers incurring costs include facilities owned by private firms only. The administrative costs to Federal, State, and local governments include the costs of rule implementation—e.g., permits, monitoring, and working with facilities subject to the final rule to achieve compliance.

In the economic analysis, EPA accounted for these costs on an as-incurred basis. They are reported on a pre-tax or after-tax basis, depending on the specific component of the analysis. These costs also underlie the analysis of the social costs of the regulatory options.

B. Development of Compliance Costs

This section describes the data and methods used to estimate compliance costs of the options considered for today's final rule. Costs were developed for technology controls to address impingement mortality separately from technology controls for entrainment because the requirements of the various rule options considered may lead to different technologies being used by each facility to comply. The options considered may impose different compliance timelines for impingement mortality and entrainment control technologies, although decision making has been synchronized to avoid investments in impingement BTA controls that could later be rendered obsolete by the BTA requirements for entrainment. Different methodologies were used and each is briefly described below. More detailed information on these methodologies and costs of other technologies and regulatory approaches are available in Chapter 8 of the TDD.

1. Combined Facility-Specific and Model-Facility Approach

EPA estimated national level costs for regulated facilities under the final rule and other regulatory options. In general, facility-specific data can be used to determine the requirements that apply to a facility and whether that facility already meets the final rule's requirements. This approach requires facility-specific technical data for the approximately 1,065 facilities that EPA estimates will be subject to the final rule. The change in the number of facilities subject to the final rule compared to the number estimated at proposal is attributable to changes in how EPA accounted for baseline closures. See Appendix H of the EA for more details. An alternative approach is to develop a series of model facilities that exhibit the typical characteristics of the regulated facilities and calculate costs for each model facility; EPA would then determine how many of each model facility would be needed to accurately represent the full universe of regulated facilities.

The approach used in this effort involved calculating compliance technology costs for 338 individual facilities for which EPA had detailed technical data from its questionnaires regarding the intake design and technology. Specifically, these are the facilities that completed the detailed technical questionnaire. Where facilities reported data for separate cooling water intake structures, EPA derived compliance technology costs for each intake, and summed these intake costs to obtain total costs for each facility. EPA used the actual facility data to construct model facilities. Each model facility's costs were then multiplied by a specific weighting factor, derived from a statistical analysis of the industry questionnaire, to obtain industry-wide costs. The weighting factors are similar to the ones derived during the development of the 2004 Phase II and 2006 Phase III rules.

2. Updates to the Survey Data

For the 2004 Phase II rule analysis, EPA developed facility-specific cost estimates for all facilities and published those costs in an appendix (69 FR 41669, July 9, 2004). Since the initial implementation of the 2004 Phase II rule, EPA identified several concerns with using only the facility-specific costing approach, and the use of those costs in Appendix A. Since 2004 EPA has collected data from industry and other groups as described in Section III of the proposed rule (76 FR 22183, April 20, 2011). These data generally reflect changes to actual intake flow, design intake flow, intake velocity, technology in place, and operational status. EPA developed a new master database including this new data to supplement the data from the detailed technical questionnaire. Although it has been more than 10 years since the detailed technical questionnaire was initially collected, EPA has undertaken more than 50 site visits and reviewed available literature. In addition, EPA compared its data with that collected by Edison Electric Institute, Electric Power Research Institute, and the Energy Information Administration. On the basis of that review, EPA concluded that the master database is representative and reasonably reflects costs for all facilities.[102] The following section describes how EPA used this new database to estimate compliance costs.

3. Tools for Developing Compliance Costs

During development of the 2004 Phase II rule, EPA began developing a spreadsheet-based tool that would provide facilities and permit authorities with a simple and transparent method for calculating facility-specific

[102] EPA notes that, while it has not collected updated technical information for every facility, it has updated financial data, as discussed later in this section.

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compliance costs. EPA refined the tool in developing the Phase III regulations. EPA has since made further refinements to the cost tool, which was used to calculate the compliance costs for impingement mortality for today's final rule. The cost tool employs a decision tree (for a graphical presentation of the decision tree, see Chapter 8 of the TDD) to determine a compliance response for each model facility. The decision tree assigns a technology costing ''module'' for the retrofit to a given technology. Impingement cost estimates are derived through a series of computations that apply facility-specific data (such as DIF, width of intake screens, and such) to the selected technology module. Cost tool outputs include capital costs, incremental operation and maintenance costs, and installation downtime (in weeks).

To calculate the compliance costs of retrofitting to closed-cycle cooling for controlling entrainment, EPA used a second tool based on a cost-estimating spreadsheet using a modified version of a similar tool developed by the Electric Power Research Institute (EPRI). EPRI's first draft methodology presented three levels of capital cost according to the relative difficulty of the retrofit project (easy, average, and difficult). For electric generators, EPA used costs for the average level of difficulty because it was developed across a broad spectrum of facilities and is the most appropriate for estimating national level costs rather than lower or upper bounds. For manufacturers, EPA used the difficult level of retrofit costs. This reflects the more complex water systems and technical challenges to retrofitting closed-cycle cooling at multiple locations within a manufacturing facility. In site visits, EPA found the largest manufacturing facilities had multiple intakes, distributed the water to multiple production processes, have already significantly increased water reuse as a result of water audits, and generally operate a complicated water distribution network at the entire facility, and would therefore require multiple retrofits to convert the facility to be commensurate with closed-cycle recirculating system.[103] Accordingly, EPA determined that the difficult level of retrofit costs is more representative for purposes of estimating national level costs. EPA's tool includes additional modifications to EPRI's methodology, such as increased compliance costs for approximately 25 percent of facilities to reflect the additional expense of noise control or plume [104] abatement, and using only the cooling water flow rate for non-contact cooling water flow [105] for purposes of estimating costs for closed-cycle cooling. EPA has included the spreadsheet tools in the docket for today's final rule to assist both facilities and permit authorities in estimating compliance costs (see DCNs 12–6650 and 12–6651 for the cost tool, as well as and DCN 10–6930 for EPRI's retrofit analysis).

4. Which technologies form the basis for compliance cost estimates?

EPA identified two broad classes of control technologies that may be used singularly or in combination to comply with the final rule. These classes of control technologies are (1) technologies that address impingement mortality, and (2) technologies that address entrainment. For further details, see Section VI.

For the impingement mortality requirements, EPA analyzed data from a wide variety of technologies and facilities, and concluded that modified (Ristroph or equivalent) 3/8″ mesh traveling screens with fish-friendly fish handling and returns are the most appropriate basis for determining compliance costs.[106] As discussed in Section VI of this preamble, a facility may also comply with impingement mortality requirements by meeting a low velocity compliance alternative, operating a closed-cycle recirculating system as defined at § 125.92(c), or employing an existing offshore velocity cap as defined at § 125.92(v). On the basis of facility-specific data, EPA made a preliminary assessment of which model facilities would not currently meet impingement mortality requirements through any of these pre-approved technologies, and assigned technology costs on the basis of modified traveling screens with a fish handling and return system if the existing intake used traveling screens. If the intake does not currently use traveling screens, EPA assigned costs for installing technologies that would comply with the low velocity compliance alternative (larger intakes, wedgewire screens, or variable speed pumps) based on site-specific conditions. These assigned technologies will meet the BTA standard (see § 125.94(b)). Although EPA no longer requires installation of barrier nets or equivalent technologies to protect shellfish in all tidal waters, EPA included the cost of barrier net technology at approximately 10 percent of the intakes as a cost component for the ''systems'' approach to compliance with the IM standards.

EPA also analyzed the costs of those options associated with entrainment requirements based on wet cooling systems. EPA also evaluated other technologies for reducing entrainment, such as seasonal operation of cooling towers, partial towers, variable speed pumps, and fine-mesh screens. The costs of the final rule include but are not limited to permit applications; characterization of the source water, intake structures and any technologies in place; studies of impingement and entrainment; and recordkeeping, monitoring, and reporting. The costs also include costs of technologies for complying with the BTA for IM; the cost of additional technologies that may be required to meet the site-specific BTA for entrainment are not included, nor are costs for additional measures that may be required for protection of listed threatened and endangered species. Section VI further describes the performance of these technologies. A detailed discussion of how the costs were developed is in Chapter 8 of the TDD.

5. How is installation downtime assessed?

Installation downtime is the length of time that a facility might need to shut down for installing a compliance technology. Downtime estimates primarily assume that the facility would need to completely shut down operations for some portion of the installation period to retrofit an intake, such as relocating an intake, connecting wet cooling systems into the facility, or reinforcing condenser housings. EPA estimated downtime as incremental outages, taking into account the periodic outages all facilities incur as part of preventative maintenance or routinely scheduled outages. For example, nuclear facilities have refueling outages approximately every 18 months lasting

[103] A refinery, for example, may have dozens of heat exchange processes throughout the facility, including a mix of wet and dry non-contact cooling equipment.

[104] The EPRI tool includes drift abatement technologies in its cost assumptions, so no additional costs were included for drift eliminators.

[105] As described in the TDD, EPA used only non-contact cooling water flows in determining the proper size for wet cooling towers. Cooling towers are not widely used for contact cooling or process water, so these flows were excluded. For electric generators, the vast majority of flow is non-contact cooling, but manufacturers are more varied in their water usage.

[106] Note that this does not preclude the use of other technologies; EPA simply used the available performance data in deriving the performance requirements. EPA's research has shown that other technologies may also be capable of meeting the final rule requirements; however, these technologies are not available at all facilities.

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approximately 40 days.[107] The entrainment control implementation periods under Proposal Option 2, 10 years for fossil fuel facilities and 15 years for nuclear facilities, would provide facilities with an opportunity to schedule the retrofit when other major upgrades are being done, thereby significantly reducing downtime.

For most facilities subject to impingement mortality, EPA assigned no incremental downtime. Facilities that are replacing or rehabilitating existing traveling screens typically do so one intake bay at a time without affecting the overall operations.[108] EPA has also found that facilities that need to scrub screens do so during other routinely scheduled outages. For some compliance technologies, however, such as relocating an intake or expanding an existing intake to lower the intake velocity, several weeks of downtime may be incurred because these are more invasive tasks. See TDD Exhibit 8–4 for EPA's net construction downtime for the various IM compliance technologies.

EPA reviewed historical retrofit data and site visits conducted since 2004 and has largely retained its assumptions for downtime from the Phase II and Phase III rules for facilities retrofitting to closed-cycle cooling. On average, EPA assumes the net installation downtime for retrofitting to closed-cycle cooling for non-nuclear electric generators is 4 weeks. This total downtime allows for the tie-in of the closed-cycle system to the existing cooling water system. The refueling outage downtime, the safety-sensitive nature of nuclear facility retrofits, and other data in EPA's record supports 28 weeks as the net construction downtime for nuclear facilities. EPA converted downtime for manufacturing facilities that use cooling water for power and steam generation into the incremental cost for purchasing electricity during the outage. For individual process units other than power generation units at a manufacturing facility, on average the downtime was assumed to be zero. In EPA's extensive experience with manufacturers, EPA's record reflects that manufacturers are generally able to shut down individual intakes for specific process lines, use inventory approaches such as temporary increases of intermediate products, and develop other workarounds without interrupting the production of the entire facility. For further discussion of how EPA accounted for installation downtime in estimating national costs, see below.

6. How is the energy penalty assessed?

The term *energy penalty* in relation to a conversion to closed-cycle cooling has a number of different interpretations. The first is the extra power required to operate fans at a mechanical draft cooling tower and additional pumping requirements (sometimes referred to as auxiliary energy requirements or parasitic loads). The second is the lost power output because of the reduction in steam turbine efficiency from an increase in cooling water temperature relative to once-through cooling (often referred to as the turbine efficiency penalty or turbine backpressure penalty). EPA is clarifying that it views the former as incremental O&M costs, and the latter is EPA's interpretation of the energy penalty. Energy penalty costs apply only to facilities retrofitting to closed-cycle cooling without replacing the condenser. Facilities installing a new impingement mortality technology will not generally face an energy penalty and will generally see little or no measureable change in auxiliary power consumption. EPA's national-level costs include both these costs. The auxiliary power consumption was included as a separate component in the operation and maintenance costs and was assessed for all facilities. The turbine efficiency penalty was typically expressed as a percentage of power output. EPA estimates the turbine efficiency energy penalty for nuclear and non-nuclear power generation would be 2.5 and 1.5 percent, respectively (see Chapter 8 of the TDD). For most manufacturers generating their own electricity, EPA assumed the same energy penalty for turbine efficiency loss as estimated for non-nuclear power facilities (i.e., 1.5 percent).

7. How did EPA assess facility-level costs for the national and regional economic impacts analysis?

As part of the economic impact analysis, EPA assessed the impact of the final rule's requirements on electric generators in the context of national and regional electricity markets. For this analysis, EPA used the Integrated Planning Model (IPM®), a comprehensive electricity market optimization model that assesses such impacts within the context of regional and national electricity markets. EPA has used IPM to analyze the impacts of various regulatory actions affecting the electric power sector over the last decade, particularly Clean Air Act regulations.

Because IPM requires facility-specific costs for each analyzed facility, yet compliance costs were developed as weighted sums of model facility costs, EPA developed a method to distribute the aggregate costs to facilities that were not themselves model facilities. For these facilities, EPA converted facility-level costs developed for model facilities to a cost per mgd DIF and then averaged these values to derive cost equations using DIF as the independent variable. These cost equations provide average costs that can be applied to any facility by simply scaling to that facility's DIF. For details on the IPM analysis, see the EA, Chapter 6. For details on facility cost development, see the TDD, Chapter 8.

8. How did EPA assess costs for new units?

Power generation and manufacturing units that are a *new unit* as defined at § 125.92(u) must meet an entrainment reduction performance standard based on closed-cycle cooling or an equivalent reduction in entrainment for the cooling water component of the intake flow based on the DIF. This section briefly describes the data and methods used to estimate compliance costs for new units at existing electric generators and manufacturers. Chapter 8 of the TDD has a complete description of the methodology.

a. New Units at Existing Electric Generators

Compliance costs for new units at existing electric generators are estimated using a similar methodology to that used for estimating compliance costs for existing facilities. As described in Chapters 6 and 8 of the TDD, however, there are a number of differences in costs between a closed-cycle cooling retrofit at an existing facility compared to installing closed-cycle cooling at a new unit. In general, these differences result in lower costs for the installation of a closed-cycle recirculating system at a new unit (as compared to a retrofit scenario), due to improved efficiency of the turbine, the elimination of construction downtime, greater ease of integrating the closed-cycle system into the design and construction of the new unit, offsetting costs of certain system and construction components, and greater overall system optimization.

EPA could not determine precisely which facilities will construct new units. Instead, EPA used an approach to estimate what portion of the new capacity (i.e., additional megawatts capacity to be constructed each year) would be subject to the final rule. Using national projections of increased

[107] Nuclear Energy Institute reported average length of outage from 2003 to 2009.

[108] EPA's data shows that facilities have an average of 4 to 5 bays.

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generating capacity,[109] EPA categorized the new capacity into three groups for 316(b) compliance purposes: (1) Subject to the Phase I rule,[110] (2) subject to today's final rule, but projected to install a cooling system that complies with the rule regardless of the rule requirements,[111] and (3) subject to today's rule and projected to incur compliance costs. Exhibit IX–1 presents the estimated total new capacity and the estimated capacity for new stand-alone units.

EXHIBIT IX–1

Fuel type	Total including Phase I	Existing facility new units only
	New Capacity (MW)	Stand-Alone (MW)
Fossil Fuel	295	80
Combined Cycle	3,264	147
Total	3,559	227

Costs for closed-cycle cooling are assigned to a portion of new stand-alone units, as shown the generating capacities in Exhibit IX–3.

EXHIBIT IX–3

Fuel type	Annual only	24-year total only
	Stand-Alone MW	Stand-Alone MW
Fossil Fuel	8	191
Combined Cycle	15	353
Total	23	544

EPA then estimated the total costs for the third group (i.e., those units that would incur compliance costs) to comply with requirements for new units. EPA used certain assumptions regarding cooling system design to modify cost equations used for estimating closed-cycle retrofit costs at existing units and then applied the cost equations to the portion of projected new unit generating capacities that would be subject to the new unit provisions of today's rule. These costs include capital [112] and O&M costs, as well as a reduction in net generating capacity due to auxiliary power consumption to operate the closed-cycle recirculating system. Due to the complex nature of constructing a new unit, there is no increase in the length of the construction project as a result of employing a closed-cycle system; similarly, there is no downtime, as the unit has not yet begun operating. See Chapter 8 of the TDD for more information.

b. New Units at Existing Manufacturers

On the basis of site visits to manufacturing facilities, EPA has observed that manufacturers are increasingly taking advantage of water conservation and reuse measures as a means of cost-cutting. EPA also notes that manufacturers are subject to a wide variety of ELGs and that, in the course of complying with requirements for those ELGs, a facility may also reduce its intake flow. (See Chapter 4 of the TDD.) A new unit provides the opportunity to employ such measures to the fullest extent in designing the new unit. The availability of water conservation and reuse opportunities, coupled with operational flexibility at facilities with multiple industrial processes, leads EPA to conclude that facilities installing new units at existing manufacturers will comply with the new unit provisions through achieving the 90 percent reduction required at § 125.94(e)(2). Thus, EPA concluded that the new unit provisions would result in no additional compliance costs for achieving flow commensurate with closed-cycle cooling at new units.[113]

To the extent that manufacturers are not able to incorporate water reuse measures as a means of complying with the new unit provision, EPA's estimate of new unit costs for manufacturers may be an underestimate. Manufacturers generally withdraw less water than electric generators (including manufacturers who generate their own electricity). Thus EPA has concluded that any underestimation would be insignificant.

C. Social Costs

EPA assessed the costs to society resulting from the final rule and other options considered in development of this rule. The findings presented in this section assume that facilities with impoundments will qualify as having closed-cycle recirculating systems in the baseline.[114] As a result, EPA assigned no compliance technology costs to these facilities; however, these facilities remain subject to today's rule and are assigned administrative costs. To the extent that some of these facilities do not qualify as having closed-cycle recirculating systems in the baseline, the costs reported in this section may be underestimates. The social cost of regulatory actions includes costs to electric generators and manufacturers to comply with the final rule, and costs to States and the Federal government to administer the rule. These costs are the opportunity costs to society of employing scarce resources to prevent the environmental damage that would occur without today's rule. EPA estimated total social costs for existing and new units at existing facilities.

In estimating social costs, EPA assumed that the final rule and other options considered in development of this rule will not affect the aggregate quantity of electricity or other affected goods and services sold to consumers. Thus, the social cost of regulatory requirements includes no loss in consumer and producer surplus from reduced sales of electricity or other goods and services produced by regulated facilities. The Agency calculated the social cost of the final

[109] Capacity increases include considerations for fuel type. See Chapter 8 of the TDD for details.

[110] New capacity that is part of a new facility (as defined by the Phase I rule) is subject to separate requirements not addressed by today's rule. Today's requirements for new units require flow reduction commensurate with a closed-cycle recirculating cooling system.

[111] Data in the record show a marked increase in the use of closed-cycle cooling in facilities constructed in recent years and for those projected to be constructed in the near future. These data indicate that in the 1990s (prior to the Phase I rule), 83 percent of new cooling systems installed were closed-cycle cooling systems and that the current trend was approximately 97 percent. Based on these data EPA assumed that 75 percent to 90 percent of new units will be designed with a closed-cycle recirculating cooling system regardless of the requirements of today's rule. See DCN 12–6672. As a result, this category of new capacity was not assigned any compliance costs.

[112] The record indicates that the total estimated capital cost for installing a closed-cycle recirculating system at a new unit to comply with today's rule ranges from a negative value (as compared to the cost for installing a once-through system) to a positive value that could approach the cost of an existing facility retrofit. Said differently, if one assumes that the new unit would have constructed a new intake structure, EPA's record shows that the capital costs for the new unit once-through system would be greater than if the new unit installs a closed-cycle recirculating system. (See DCN 10–6650.) Alternatively, if the new unit did not require modification of the existing cooling system infrastructure, then the capital costs for installing a closed-cycle recirculating system would be similar to an existing facility retrofit minus some tie-in costs since the condenser is being replaced. While EPA envisions that the actual costs will vary (i.e., some will be in the negative portion of the range and others will be in the positive), EPA is also unable to project what cooling water intake arrangements a new unit will use. Consequently, for all new units, EPA selected a capital cost equal to the midpoint between the tower only and the easy retrofit costs. As a result, EPA assumed that the capital costs for these units was $154 per gpm in 2009 dollars which converts to $30,800 to $60,060 per MW capacity depending on fuel type. For a more detailed discussion, see TDD Chapter 8.

[113] EPA also notes that some manufacturers may also be able to increase reuse to a degree where the facility no longer meets the applicability thresholds of today's rule.

[114] In other words, EPA assumed facilities indicating use of an impoundment in response to their technical survey have lawfully created such impoundments for the purposes of cooling water.

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rule and the other options considered using two discount rates: 3 percent and 7 percent.

For existing facilities, EPA assumes that all facilities subject to the final rule will begin bearing costs associated with today's rule beginning as soon as 2014, and likely complete investments associated with today's rule by 2030, depending on the technology-installation schedules for the final rule and other regulatory options considered.[115] EPA performed the social cost analysis over a 51-year period to reflect (1) the last year in which individual facilities are expected to achieve compliance (2030) under the final rule or any of the options considered, (2) the life of the longest-lived compliance technology installed at any facility (30 years), and (3) a period of five years after the last year of compliance technology operation during which benefits continue to accrue. Under this framework, the last year for which EPA has calculated projected costs is 2059, with benefits continuing beyond 2059, though on a diminishing basis, through 2064.[116]

To estimate social costs for existing facilities, EPA developed a year-explicit schedule of compliance outlays over the 46-year period from 2014 to 2059 according to cost-incurrence assumptions (for details on cost-incurrence assumptions, see EA, Chapter 3). EPA then adjusted these costs for predicted real change (i.e., adjusted for inflation) to the year of their incurrence and discounted all costs to the beginning of 2013, the promulgation year used for the analysis. Because the analysis period extends beyond the useful life of some compliance equipment, the social cost analysis accounts for re-installation of impingement mortality compliance technologies after the end of their initial useful life periods. However, for the regulatory option that requires a specific entrainment control technology (e.g., wet cooling systems)—Proposal Option 2—EPA does not expect regulated facilities to completely rebuild these systems (components such as piping and the concrete basin can be reused). EPA accounted for other technology replacement costs (such as pumps and fill material) as part of ongoing operations and maintenance expenses.

For new units at existing electric generators, EPA calculated an average annual amount of new capacity to be constructed during the 46-year social cost analysis period, beginning in 2014. While EPA does not expect the annual construction of new units to be constant, predicting the year-to-year fluctuations would be resource intensive. On average, EPA assumes that its estimate of new unit costs is reasonable. EPA accounted for compliance costs for these units on an as-incurred basis, as done for existing facilities. Similar to compliance costs for facilities subject to the final rule, EPA analyzed costs incurred by State and Federal governments for administering the regulation on a year-explicit basis over the 46-year social cost analysis period.

Exhibit IX–4 presents social costs for existing units at existing facilities under the final rule and other options considered, calculated using 3 percent and 7 percent discount rates. At the 3 percent discount rate, EPA estimates total annualized social costs of $272 million for the existing unit provision of today's rule, $252 million for Proposal Option 4, and $3,643 million for Proposal Option 2. At the 7 percent discount rate, these costs are $295 million for today's rule, $272 million for Proposal Option 4, and $3,583 million for Proposal Option 2.[117] See the EA (Chapter 7) for an explanation of why the annualized costs at the 3 percent discount rate are lower than the annualized costs at the 7 percent discount rate for the final rule and Proposal Option 4, while the inverse is the case for Proposal Option 2 (annualized costs at the 3 percent discount rate are higher than at the 7 percent discount rate). The largest component of social cost is the cost of regulatory compliance incurred by regulated facilities (as opposed to administrative costs estimated for States and the Federal government). These costs include (1) one-time technology and other initial costs of complying with the rule, (2) one-time costs of installation downtime, (3) annual fixed and variable operating and maintenance costs, including auxiliary energy requirement, (4) value of energy penalty from operation of compliance technology, and (5) permitting costs (initial and follow-up start-up costs, initial permit costs, annually recurring costs associated with monitoring, and non-annually recurring permitting costs).

Compliance costs estimated for electric generators account for the largest share of total compliance-related social cost and direct compliance cost under all three options. On a per-facility basis and at the 3 percent discount rate, the annualized pre-tax compliance costs for the electric generators segment under today's final rule are $0.4 million, $0.4 million under Proposal Option 4, and $6 million under Proposal Option 2.[118] For manufacturers, the average cost per regulated facility at the 3 percent discount rate is $0.1 million under the final rule and Proposal Option 4, and $0.4 million under Proposal Option 2.[119] EPA's analysis found a similar profile of per facility costs using the 7 percent discount rate (see EA Chapter 7 for additional detail). EPA's estimate of Federal and State government costs for administering this rule is small in relation to the estimated direct cost of regulatory compliance. EPA estimates $1 million in annual administrative costs to States and Federal government for the final rule, using both the 3 and 7 percent discount rates. These cost values are the same for Proposal Option 4. EPA estimates $0.7 million in annual administrative costs to States and the

[115] EPA conducted the cost and economic impact analyses on a calendar-year basis. For these analyses, EPA used calendar year 2013 as the promulgation year of today's rule and 2014 as the first post-promulgation analysis year. This slight difference from the actual promulgation year of 2014 results from the fact that EPA completed its cost and economic impact analyses for the final rule and alternative options before EPA decided to delay promulgation from 2013 to 2014. Because the rule is being promulgated during the first half of 2014, EPA concluded that it would be reasonable to continue using 2013 as the assumed promulgation year for the regulatory analysis. EPA expects the differences in the estimated costs and benefits of the rule due to this slight imprecision to be minimal.

[116] For this analysis, EPA assumed that the last year of technology installation for all regulated facilities under any of the regulatory options—i.e., 2030—is also the first year of steady-state compliance with regulatory requirements.

[117] Because EPA was unable to identify those facilities for which entrainment control technology would be established as BTA standards on a site-specific basis, the Agency did not analyze technology costs associated with these site-specific requirements. Consequently, the cost and economic analyses conducted in support of today's rule assume that under the existing unit provision of the final rule and Proposal Option 4, Electric Generators and Manufacturers install IM technology only. These analyses also assume that under Proposal Option 2, Electric Generators with DIF exceeding 125 mgd install only cooling towers and all other Electric Generators install only IM technologies. Under Proposal Option 2, a small number of Manufacturers are assigned both IM and entrainment control technologies because of engineering issues associated with maintaining separation of contact and non-contact cooling water in some manufacturing operations. Although EPA did not estimate technology costs for facilities for which entrainment technology is established as BTA on a site-specific basis, EPA did include the costs for data collection and studies that facilities will need to perform in order to provide information to Directors to make these site-specific determinations. EPA included these costs in the administrative costs that are estimated for the final rule and other options considered.

[118] Calculated by dividing direct compliance costs for each type of facility by the total of 544 electric generators subject to today's rule on the basis of facility count-based weights (see EA Appendix H).

[119] Calculated using the total of 521 manufacturers subject to today's rule on the basis of technical weights (see EA Appendix H).

Federal government for Proposal Option 2, regardless of the discount rate used.

EXHIBIT IX–4—TOTAL ANNUALIZED SOCIAL COSTS—EXISTING UNITS AT EXISTING FACILITIES

[in millions, 2011 dollars] [a]

	Proposal option 4	Final rule	Proposal option 2
Using 3 percent discount rate			
Direct Compliance Costs:			
Electric Generators	$202.9	$203.7	$3,413.3
Manufacturers	47.8	67.7	229.2
Total Direct Compliance Cost	250.7	271.4	3,642.5
State and Federal Administrative Costs	1.0	1.0	0.7
Total Social Costs	251.8	272.4	3,643.2
Using 7 percent discount rate			
Direct Compliance Cost:			
Electric Generators	219.2	220.0	3,339.3
Manufacturers	51.9	74.2	243.0
Total Direct Compliance Cost	271.1	294.3	3,582.3
State and Federal Administrative Costs	1.0	1.0	0.7
Total Social Costs	272.1	295.3	3,583.0

[a] Cost estimates exclude costs associated with baseline closure facilities.

EPA also estimated the cost for installing closed-cycle recirculating systems at new units at existing electric generators, to reflect the costs of today's rule. As shown in Exhibit IX–5, EPA estimated that the new unit provision of the final rule will result in an annualized cost of $2.5 million and $2.0 million using 3 percent and 7 percent discount rates, respectively, including compliance costs to facilities and administrative costs to States and Federal government.

The Agency estimated that at a 3 percent discount rate, the total social cost of the final rule, including the existing and new unit provisions, will be $275 million. At a 7 percent discount rate, this cost is $297 million.

EXHIBIT IX–5—ANNUALIZED TOTAL SOCIAL COST OF THE FINAL RULE—EXISTING AND NEW UNITS AT EXISTING FACILITIES

[In millions, 2011 dollars] [a b]

	3% Discount rate	7% Discount rate
New Units	$2.5	$2.0
Existing Units	272.4	295.3
Existing and New Units	274.9	297.3

[a] Cost estimates exclude costs associated with baseline closure facilities.

[b] Values may not add due to rounding.

D. Economic Impacts

EPA used several analytic approaches to assess the economic impact of today's rule and the other options considered, on electric generators and manufacturers. EPA conducted separate analyses for electric generators and manufacturers using different methodologies for each regulated facilities segment. The following sections summarize the methodologies EPA used to conduct the economic impact analyses and the findings of these analyses. EPA conducted the economic impact analyses discussed in this section for existing facilities; the Agency used compliance cost estimates from the EPA engineering analysis (see TDD Section X.B).

1. Electric Generators

For the electric generators segment, EPA assessed the economic impact of the existing unit provision of the final rule and other options it considered in three ways: (1) The financial burden associated with a particular regulatory option on facilities and entities that own them, (2) how potential changes in the price of electricity would affect electricity consumers, in general, and residential households, in particular, and (3) broader economic impacts on the electricity market, taking into account the interconnectedness of regional and national electricity markets. In preparing the first two sets of analyses, EPA developed and used sample weights to extrapolate impacts assessed initially at the level of sample of facilities, to the full population of facilities subject to the final rule. For information on how EPA developed and used sample weights, see the EA, Appendix H.

In addition, EPA assessed the impact of the new unit provision of the final rule on decisions of existing facilities to construct stand-alone new units that would be subject to the new unit provision. EPA made this assessment in two ways: (1) On the basis of comparison, on a per MW basis, of compliance costs for new units to the overall cost of building and operating generating units and (2) as is the case with the existing unit provision, in the context of regional and national electricity markets, taking into account their interconnectedness.

a. Cost-to-Revenue Analysis for Regulated Facilities and Their Parent Entities—Existing Unit Provision of the Final Rule

EPA assessed the cost to regulated facilities and their parent entities on the basis of a cost-to-revenue analysis. For each analysis level (facility and parent entity), the Agency assumed, for analytic convenience and as a worst-case scenario, that none of the compliance costs would be passed on to consumers through electricity rate increases and, instead, would be absorbed by regulated facilities and their parent entities.[120] EPA developed

[120] As discussed in EA Chapter 2A: Industry Profiles, the majority of regulated electric generators operate in States with regulated electricity markets. EPA estimates that facilities located in these States may be able to recover compliance cost-based increases in their production costs through increased electricity prices. This depends on the business operation model of the facility owner(s), the ownership and operating structure of the facility itself, and the role of market mechanisms used to

Continued

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this analysis for 544 electric generators.[121]

i. Cost-to-Revenue Analysis for Regulated Facilities

To provide insight into the potential significance of the compliance costs to regulated facilities, EPA calculated the ratio of annualized after-tax compliance costs to baseline annual facility-level revenues. In the cost-to-revenue comparisons, EPA used cost-to-revenue thresholds of 1 and 3 percent to categorize facilities according the potential economic impact of the rule. EPA concludes that facilities incurring costs below 1 percent of revenue will not face significant economic impacts, while facilities with costs of at least 1 percent but less than 3 percent of revenue have a chance of facing economic impacts, and facilities incurring costs of at least 3 percent of revenue have a higher probability of significant economic impacts. For a more detailed discussion of the methodology EPA used for the facility-level cost-to-revenue analysis, see EA Chapter 4.

Exhibit IX–6 presents a summary of the facility-level cost-to-revenue analysis results for the final rule and other options considered. EPA estimates that overall, under the final rule, 86 percent of regulated facilities will incur compliance costs of less than 1 percent of revenue. Under Proposal Option 4, 87 percent of regulated facilities would also incur costs of less than 1 percent of revenue. EPA estimates that Proposal Option 2 would result in 42 percent of facilities incurring costs exceeding 1 percent of revenue, and 43 percent incurring costs exceeding 3 percent of revenue.

EXHIBIT IX–6—FACILITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS FOR THE FINAL RULE AND OPTIONS CONSIDERED [a]

Option	Number of facilities with cost-to-revenue ratio					
	< 1%		≥ 1% and < 3%		≥ 3%	
	#	%	#	%	#	%
Proposal Option 4	475	87.4	35	6.5	31	5.7
Final Rule	470	86.5	40	7.4	31	5.7
Proposal Option 2	228	41.9	79	14.5	235	43.2

[a] Facility counts exclude baseline closures.
[b] EIA reports no revenue for 1 facility (2 on a weighted basis). Therefore, EPA conducted this analysis for 339 facilities (542 on a weighted basis). For more information on facility sample weights see EA Appendix H.

ii. Cost-to-Revenue Analysis for Regulated Parent Entities

EPA also assessed the economic impact using the cost-to-revenue metric at the level of the parent entity. This analysis, which focuses on domestic parent entities with the largest ownership share in the facility, provides insight on the impact of compliance requirements on those entities that own more than one regulated facility. The analysis helps to answer the question of whether owning multiple facilities that are required to comply with today's rule causes financial stress at the entity level. For each identified parent entity, EPA aggregated facility-level, annualized, after-tax compliance costs to the level of the parent entity and compared these entity-level costs to entity-level revenue.

Similarly to the facility-level analysis, EPA used cost-to-revenue thresholds of 1 and 3 percent to categorize facilities according the potential economic impact of the rule. EPA used two weighting approaches for this analysis: (1) Facility-level weights, but without entity-level weights and (2) entity-level weights, but without facility-level weights. These approaches, which are described in Appendix H of the EA, provide a range of estimates for the number of entities incurring compliance costs and the costs incurred by any entity that owns a regulated facility. (For a more detailed discussion of the methodology used for the entity-level cost-to-revenue analysis, see EA Chapter 4).

Exhibit IX–7 presents results for the entity-level analysis for the two weighting approaches. EPA estimates that between 123 and 159 entities own regulated facilities. Further, the Agency estimates that between 91 and 94 percent of parent entities will incur annualized costs of less than 1 percent of revenues under the final rule. This finding also holds under the two other options EPA considered, with between 91 and 94 percent of entities incurring costs of less than 1 percent of revenue under Proposal Option 4 and between 70 and 78 percent under Proposal Option 2.

EXHIBIT IX–7—ENTITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS [b]

Parent entity type	Total number of entities	Number of entities with cost-to-revenue ratio of							
		< 1%		≥ 1% and < 3%		≥ 3%		Unknown [a]	
		#	%	#	%	#	%	#	%
Using Facility-Level Weights:									
Proposal Option 4	123	112	91.1	3	2.4	0	0.0	8	6.5
Final Rule	123	112	91.1	3	2.4	0	0.0	8	6.5
Proposal Option 2	123	86	69.9	17	13.8	12	9.8	8	6.5
Using Entity-Level Weights:									
Proposal Option 4	159	150	94.2	0	0.0	0	0.0	9	5.8

sell electricity. In contrast, in States where electric power generation has been deregulated, cost recovery is less certain. While facilities operating within deregulated electricity markets may be able to recover some of their additional production costs through increased revenue, EPA cannot determine the extent of cost recovery ability for each facility.

[121] EPA calculated this number as a weighted estimate using facility count-based weights. This number excludes facilities assumed either to have already retired their steam operations or expected to do so in the future.

EXHIBIT IX–7—ENTITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS [b]—Continued

Parent entity type	Total number of entities	Number of entities with cost-to-revenue ratio of							
		< 1%		≥ 1% and < 3%		≥ 3%		Unknown [a]	
		#	%	#	%	#	%	#	%
Final Rule	159	150	94.2	0	0.0	0	0.0	9	5.8
Proposal Option 2	159	124	78.1	18	11.6	7	4.4	9	5.8

[a] EPA was unable to determine revenues for 8 parent entities (9 weighted).
[b] This analysis assumes no cost pass-through to electricity consumers.

b. Potential Electricity Price Effects—Existing Unit Provision of the Final Rule

As an additional measure of economic impact, EPA conducted two assessments of the potential price effects on electricity of today's rule: (1) The annual increase in electricity costs per MWh (megawatt hour) of total electricity sales and (2) the potential annual increase in household electricity costs. For analytic convenience and as a worst-case scenario, these assessments assume that all compliance costs will be passed through on a pre-tax basis to consumers as increased electricity prices. This full cost pass-through assumption represents a ''worst-case'' impact scenario from the perspective of electricity consumers. Facilities that are merchant providers can pass along costs only to the degree that they are competitive with other generators in the dispatch process.[122] This assumption is the opposite of EPA's assumption in the facility- and entity-level analyses discussed above—that facilities will pass none of the compliance costs through to consumers in electricity rate increases. If facilities are able to pass through all costs, the impacts in the previous subsection would not occur. The two conditions (no cost pass-through and full cost pass-through) could not occur at the same time. Thus, the results of the electricity price-effects analyses discussed in this section, and of the facility- and entity-level analyses discussed in Section IX.D.a.1, should not be combined. EPA conducted this analysis for 544 electric generators.

i. Compliance Cost per Unit of Electricity Sales

EPA assessed the potential increase in electricity rates by NERC region based on the annual cost of the regulatory options per unit of electricity sold. The Agency used two data inputs: (1) Total pre-tax compliance cost by NERC region, and (2) estimated total electricity sales in the year 2020, to gauge the full effects of the rule. To calculate the total estimated annual cost in each NERC region, the Agency summed sample-weighted, pre-tax annualized compliance costs over regulated facilities by region. EPA then calculated the approximate average price impact per unit of electricity consumption by dividing total compliance costs by the reported total MWh of sales in each NERC region. (Details of this analysis are presented in the EA, Chapter 4.)

As reported in Exhibit IX–8, under the existing unit provision of the final rule, annualized compliance costs (in cents per kWh sales) range from nearly $0.00 in the WECC region to $0.040 in the HICC region. EPA reached the same findings for Proposal Option 4. Under Proposal Option 2, costs range from $0.00 in the WECC region to $0.351 in the HICC region. On average, across the United States, the final rule and Proposal Option 4 result in a cost of $0.009 per kWh, while Proposal Option 2 results in a higher cost of $0.155 per kWh.

EXHIBIT IX–8—COMPLIANCE COST PER UNIT OF ELECTRICITY SALES IN 2020 BY REGULATORY OPTION AND NERC REGION

[2011 ¢/KWh sales] [a b]

NERC region [c d]	Proposal option 4	Final rule	Proposal option 2
ASCC	0.000	0.000	0.000
FRCC	0.014	0.014	0.171
HICC	0.040	0.040	0.351
MRO	0.010	0.010	0.174
NPCC	0.008	0.008	0.126
RFC	0.011	0.011	0.200
SERC	0.013	0.013	0.219
SPP	0.009	0.009	0.078
TRE	0.008	0.008	0.206
WECC	0.000	0.000	0.000
United States	0.009	0.009	0.155

[a] This analysis assumes full pass-through of all compliance costs to electricity consumers.
[b] Cost values exclude baseline closures.
[c] ASCC—Alaska Systems Coordinating Council; FRCC—Florida Reliability Coordinating Council; HICC—Hawaii Coordinating Council; MRO—Midwest Reliability Organization; NPCC—Northeast Power Coordinating Council; RFC—ReliabilityFirst Corporation; SERC—Southeastern Electric Reliability Council; SPP—Southwest Power Pool; TRE—Texas Reliability Entity, and WECC—Western Energy Coordinating Council.
[d] No explicitly analyzed facilities are in the ASCC region. For more information on explicitly and implicitly analyzed regulated facilities, see EA Appendix H.

[122] As discussed earlier in Section X.D.b.1, even though individual regulated facilities may not be able to recover all of their compliance costs through increased revenues, the market-level effect may still be that consumers will see higher overall electricity prices because of changes in the cost structure of electricity supply and resulting changes in market-clearing prices in deregulated electricity markets.

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ii. Cost to Households

As an additional measure of the potential electricity price effects associated with the final rule, EPA estimated the potential annual increase in electricity costs per household and by NERC region. EPA used total annualized pre-tax compliance cost per MWh of sales, as estimated for the electricity rate impact analysis discussed above and the quantity of residential electricity sales per household as reported in the 2011 EIA database. To calculate the potential annual cost impact per household, EPA multiplied the average cost per kWh by the average kWh per household estimated for each NERC region. (Chapter 4 of the EA presents details of this analysis.)

As presented in Exhibit IX–9, under the existing unit provision of the final rule, the average annual cost per residential household varies across NERC regions, ranging from $0.01 in WECC to $2.82 in HICC. EPA reached the same findings for Proposal Option 4. Under Proposal Option 2, the average annual cost per residential household also varies across NERC regions, ranging from $0.01 in WECC to $31.72 in SERC. EPA estimated that on average, for a typical U.S. household, the final rule will result in an annual cost of $1.03 in higher electricity rates per household. EPA estimates that this cost would be $1.03 per household under Proposal Option 4 and $17.23 per household under Proposal Option 2.

EXHIBIT IX–9—AVERAGE ANNUAL COST BURDEN PER RESIDENTIAL HOUSEHOLD IN 2020 FOR THE FINAL RULE AND OPTIONS CONSIDERED, AND BY NERC REGION

[2011 dollars] [a] [b]

NERC region [c] [d]	Proposal option 4	Final rule	Proposal option 2
ASCC	$0.00	$0.00	$0.00
FRCC	1.91	1.91	23.15
HICC	2.82	2.82	24.61
MRO	0.99	1.02	18.10
NPCC	0.61	0.62	9.52
RFC	1.10	1.10	20.64
SERC	1.96	1.96	31.72
SPP	1.30	1.30	10.71
TRE	1.15	1.15	30.59
WECC	0.01	0.01	0.01
United States	1.03	1.03	17.23

[a] The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.
[b] Cost estimates exclude baseline closures.
[c] ASCC—Alaska Systems Coordinating Council; FRCC—Florida Reliability Coordinating Council; HICC—Hawaii Coordinating Council; MRO—Midwest Reliability Organization; NPCC—Northeast Power Coordinating Council; RFC—ReliabilityFirst Corporation; SERC—Southeastern Electric Reliability Council; SPP—Southwest Power Pool; TRE—Texas Reliability Entity, and WECC—Western Energy Coordinating Council.
[d] No explicitly analyzed facilities are in the ASCC region. For more information on explicitly and implicitly analyzed regulated facilities, see EA Appendix H.

As noted above, this analysis assumes that facilities will pass through to consumers all compliance costs through increased electricity rates. However, facilities and owner entities might not be able to recover all these costs through rate increases, thereby reducing the impact of today's rule on electricity consumers. At the same time, EPA recognizes that electric generators that operate as regulated public utilities will generally recover environmental compliance costs through rate increases to consumers.

c. Barrier-To-Development Analysis—New Unit Provision of the Final Rule

EPA assessed the impact of the new unit provision of the final rule on decisions of existing facilities to construct stand-alone new units that would be subject to the new unit provision. As discussed earlier in this preamble, under this provision, electric power generating units that meet the definition of a new unit will be required to achieve intake flow commensurate with closed-cycle cooling. The question of potential impact of this provision on the construction of new stand-alone units is important because new stand-alone units will generally operate with higher energy efficiency and lower environmental impact than older electric generating capacity, which the new units would tend to displace as a source of electric power generation. As such, EPA sought to ensure that the new unit provision would not impede construction of stand-alone new units.

For this analysis, EPA compared the compliance costs for new units to the overall cost of building and operating generating units, on a per MW basis. The purpose of this analysis is to determine whether the required addition of a closed-cycle recirculating system (CCRS) as part of a new unit would substantially increase the cost for the new stand-alone unit, and adversely affect the decision to construct the new stand-alone unit. This analysis showed that given the low cost of CCRS in relation to the cost of new capacity, the CCRS requirement will not pose a barrier to development of new stand-alone units.

EPA also assessed the costs associated with the new unit provision of the final rule as part of its electricity market analysis, as discussed in the following section (Section IX.D). This analysis tests the impact of the new unit requirements on electricity markets accounting for the expected number and timing of new unit installations, and provides additional insight on whether the costs of complying with the new unit provision of the final rule would affect future capacity additions. This analysis found no material effect of the final rule's new unit provision on the number and type of new units that would be constructed. This finding also supports EPA's conclusion that the new unit provision will not be a barrier to development of new capacity.

d. Impacts in the Context of Electricity Markets—Existing and New Unit Provisions of the Final Rule

In the analyses for the previous 316(b) regulations, including the proposed rule, EPA used the Integrated Planning Model (IPM®),[123] a comprehensive electricity market optimization model, to assess the economic impact of regulatory options within the context of

[123] Developed by ICF, Inc.

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regional and national electricity markets. To assess facility and market-level effects of the final rule, EPA used an updated version of this same analytic system, the Integrated Planning Model Version 4.10 MATS (IPM V4.10_MATS) platform.

Use of a comprehensive, market analysis system is important in assessing the potential impact of the final rule because of the interdependence of electricity generating units in supplying power to the electric transmission grid. Increases in electricity production costs and potential reductions in electricity output at regulated facilities—due to the temporary shutdown of existing electric generating units during technology installation—can have a range of broader market impacts that extend beyond the effect on regulated facilities and their direct customers. In addition, the impact of compliance requirements on regulated facilities may be seen differently when the analysis considers the impact on those facilities in the context of the broader electricity market instead of looking at the impact on a stand-alone, single-facility basis.

The IPM V4.10_MATS platform provides outputs for the NERC regions that lie within the continental United States. This IPM platform does not analyze electric power operations in Alaska and Hawaii because these operations are not connected to the continental U.S. power grid. The IPM V4.10_MATS platform is based on an inventory of U.S. utility- and non-utility-owned boilers and generators that provide power to the integrated electric transmission grid, as recorded in the EIA 860 (2006) and EIA 767 (2005) databases.[124] IPM does not include electric power facilities that do not provide power to the U.S. power grid (e.g., some generating units at industrial facilities). The IPM V4.10_MATS universe consists of 14,920 generating units at 4,910 existing electric power facilities, including 520 of the 544 regulated electric power facilities subject to the final rule.[125]

This IPM V4.10_MATS platform embeds a baseline energy demand forecast from the Department of Energy's Annual Energy Outlook 2010 (AEO2010), with adjustments by EPA to account for the effect of certain voluntary energy efficiency programs. This platform also incorporates in its analytic baseline the expected compliance response to existing regulatory requirements for the following promulgated air regulations affecting the power sector: the final Mercury and Air Toxics Standards (MATS) rule; the final Cross-State Air Pollution Rule (CSAPR);[126] regulatory SO_2 emission rates arising from State Implementation Plans (SIP); Title IV of the Clean Air Act Amendments; NO_X SIP Call trading program; Clean Air Act Reasonable Available Control Technology requirements and Title IV unit specific rate limits for NO_X; the Regional Greenhouse Gas Initiative; Renewable Portfolio Standards; New Source Review Settlements; and several state-level regulations affecting emissions of SO_2, NO_X, and mercury that are already in place or expected to come into force by 2017.

In contrast to the screening-level analyses described earlier, which are static analyses and do not account for interdependence of electric generating units in supplying power to the electric transmission grid, IPM accounts for potential changes in the generation profile of individual electric power facilities and consequent changes in market-level generation costs, as a result of the final rule. The model is dynamic in that the analysis covers a multiple-decade period with information and decisions in any specific period depending on the analysis information and optimization results for the entire analysis period. The model is also forward-looking in that it uses forecasts of future conditions to make decisions for the present. Finally, in contrast to the screening-level analyses in which EPA assumed either no pass through of compliance costs (facility and entity cost-to-revenue analyses discussed in Section IX.D.a.1) or full cost pass-through (analysis of potential electricity price effects, Section IX.D.b.1), IPM assesses price and revenue effects from increased costs in competitive wholesale electricity markets, where some recovery of compliance costs through increased electricity prices is possible but not guaranteed.

In performing analyses based on the IPM V4.10_MATS platform, EPA used as its baseline a projection of electricity markets and facility operations without the final rule requirements (baseline case). As discussed above, this baseline accounts for compliance with the recently promulgated Federal air rules. EPA then overlaid this baseline with the estimated compliance costs and other operating effects—downtime for installation of IM technologies at existing units and auxiliary energy requirement to operate cooling towers at new units—for regulated facilities under the policy case.

As discussed in Appendix P of the EPA report, the IPM V4.10_MATS platform models the electric power market over the 43-year period from 2012 to 2054. Within this total analysis period, EPA looked at shorter IPM analysis periods (run-year windows)[127] to assess the effect of the final rule on national and regional electricity markets. Specifically, to assess the impact of the final rule during the period when regulated facilities temporarily suspend their operation to install compliance technologies—the short-term effects analysis or the downtime effects analysis—EPA used results reported for the 2020 IPM run year, which represent an 8-year window of 2017 through 2024.[128] The incurrence of downtime may lead to higher electricity generation costs overall, as generating units at regulated facilities are taken out of service to complete technology installation and other generating units, presumably with higher production costs, are dispatched to meet electricity demand. Because of the potential resulting increase in electricity generation costs, it is

[124] In some instances, facility information has been updated to reflect known material changes in a facility's generating capacity since 2006.

[125] Facilities excluded from the IPM analysis include three facilities in Hawaii and one facility in Alaska (i.e., areas that are outside the geographic scope of the model), four on-site facilities that are not connected to the integrated electric transmission grid, four facilities excluded from the IPM baseline as the result of custom adjustments made by ICF, and 12 facilities that did not respond to the 316(b) survey.

[126] EPA's Cross-State Air Pollution Rule (CSAPR) was promulgated to replace EPA's Clean Air Interstate Rule (CAIR), which had been remanded to EPA in 2008. However, on December 30, 2011, the U.S. Court of Appeals for the D.C. Circuit stayed CSAPR pending judicial review and left CAIR in place. On August 21, 2012 the Court issued an opinion vacating CSAPR and again leaving CAIR in place pending development of a valid replacement. On March 29, 2013, the United States filed a petition asking the Supreme Court to review the D.C. Circuit's opinion. Nevertheless, as explained above, CAIR remains in effect at this time. In light of the continuing uncertainty on CAIR and CSAPR, EPA determined it would not be appropriate or possible at this time to adjust emission projections on the basis of speculative alternative emission reduction requirements in 2020. EPA expects that the decision vacating CSAPR and leaving CAIR in place has minimal effect on the results of the analysis conducted in support of the final rule.

[127] Due to the highly data- and calculation-intensive computational procedures required for the IPM dynamic optimization algorithm, IPM is run only for a limited number of years. Run years are selected based on analytical requirements and the necessity to maintain a balanced choice of run years throughout the modeled time horizon. Each run year represents adjacent years in addition to the run year itself.

[128] As discussed earlier in this document, for the cost and economic impact analyses, EPA assumed that electric generators will install IM technologies during the 5-year window of 2018 through 2022. Because this technology-installation window falls within the time period captured by the 2020 run year (i.e., 2017 through 2024), EPA judges that 2020 is an appropriate year to capture the effects of technology-installation downtime.

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important to examine market-level effects during the period in which downtime would occur.

To assess the longer term effect of the final rule on electricity markets during the period after compliance technology is installed at all regulated facilities—the steady-state post-compliance period—EPA analyzed results reported for the IPM 2030 run year, which represents a 10-year window of 2025 through 2034.[129] Effects that may occur during this steady-state period include increased electricity production costs at regulated facilities and potential permanent losses in generating capacity from early retirement (closure) of generating units. Both effects may lead to higher overall electricity generation costs through not only the increased production cost in regulated facilities, but also through dispatch of higher production cost units to offset capacity losses, reflecting the general upward shift in production costs.[130]

EPA measured the impacts of the final rule as the difference between key economic and operational impact metrics between the baseline case and the policy case. All analysis results presented below are representative of modeled market conditions in the years 2017–2034. While costs are in 2011 dollars, they are reflective of costs in the modeled years and are not discounted to the start of EPA's analysis period of 2013.[131] In contrast to the earlier statement that the cost and economic impact analysis findings presented in this preamble may be underestimates because EPA assumed that no facilities with impoundments will install compliance technology, the market-based analysis presented in this section reflects the opposite assumption. Namely, despite the final rule's treatment of impoundments, for purposes of this analysis, none of the facilities with impoundments are treated as having closed-cycle cooling in the baseline. As a result, to the extent that some of these facilities may qualify as having closed-cycle recirculating systems in the baseline, and thus would not need to install compliance technology, the costs and economic impacts reported in this section may be overestimated.

i. Analysis Results for the Year 2030—To Reflect Steady State, Post-Compliance Operations

For the steady-state analysis (2030), EPA considered impact metrics of interest at three levels of aggregation: (1) Impact on national and regional electricity markets, (2) impact on the group of 520 regulated facilities modeled in IPM, and (3) impact on individual 520 regulated facilities.

Impact on National and Regional Electricity Markets

For the assessment of market-level impacts, EPA considered six output metrics: (1) Incremental capacity retirements (closures); (2) changes in capacity retirements as a percent of total baseline capacity (3) changes in new capacity additions; (4) changes in variable production costs per MWh, calculated as the sum of total fuel and variable O&M costs divided by net generation; (5) changes in total generation costs (fuel, variable O&M, fixed O&M, and capital); and (6) changes in wholesale electricity prices.

As shown in Exhibit IX–10, the final rule has small effects on the electricity market, on both the national and regional sub-market basis, in 2030. At the national level, the analysis shows a total net increase in retired capacity of approximately 1 GW, or less than 0.1 percent of the total baseline capacity in 2030 (capacity retirements are discussed in greater detail in the next section, Impact on Regulated Facilities as a Group). This 1 GW of net capacity loss reflects a combination of closures and avoided closures of generating units. ''Avoided closure'' means a generating unit that was projected to close in the baseline case but remains open in the policy case because of changes in the relative operating economics of generating capacity. In some instances an avoided closure can result in an avoided full facility closure. Overall, the final rule will lead to early retirement of approximately 4 GW of generating capacity and approximately 3 GW of avoided closure of capacity otherwise projected to retire by 2030, resulting in a net closure of approximately 1 GW of generating capacity. With only one exception, these retirements involve older, less efficient generating units with very low capacity utilization rates.

Five of the eight analyzed NERC regions record modest increases in retired capacity, with the largest increase, 0.8 percent of baseline retired capacity, projected to occur in TRE. One NERC region—SPP—avoids capacity closures, where 1.5 percent of capacity otherwise projected to retire in the baseline, becomes a more economically viable source of electricity in the policy case due to changes in the relative economics of electricity production across the full market, and thus avoids closure.[132] Consequently, the final rule is not expected to have a material ongoing effect on capacity availability and supply reliability at either the national or the NERC region level.

The 1 GW of retired capacity is replaced by new, more efficient, and less polluting capacity. Because the new capacity is more efficient and less costly to run than the retired capacity, it will run at a higher capacity utilization rate than the retired capacity; less new capacity is required to meet electricity demand than the retired capacity that it replaces. As shown in Exhibit IX–11, under the final rule, new capacity additions increase by 1 GW at the national level; this increase represents 0.5 percent of new baseline capacity and 0.1 percent of total baseline capacity (see Exhibit IX–10). This increase in new capacity is mostly comprised of combined cycle capacity followed by other non-steam capacity, with coal steam capacity additions remaining zero in both the baseline case and the policy case. Consequently, this analysis shows that the final rule is not likely to impede construction of new combined cycle and coal steam generating units.[133]

As reported in Exhibit IX–10, overall, the final rule has only a slight impact on electricity prices. For three out of eight NERC regions, electricity prices decline

[129] EPA expects this steady-state period to begin in the last year of the technology-installation window, i.e., 2022, and continue into the future. The 2022 analysis year is captured in the IPM 2020 run year, as opposed to the 2030 run year. However, because all analysis years represented by the 2030 run year (i.e., 2025–2034) fall outside the technology-installation window of 2018 through 2022, EPA judges that 2030 is an appropriate year to capture longer term, steady-state effects of the final rule.

[130] In seeking to minimize the cost of meeting electricity demand, IPM will tend to shift production away from regulated facilities that incur compliance costs, and will shift production to either non-regulated facilities, which incur no compliance costs, or to regulated facilities that incur relatively lower compliance costs. Any of these changes—whether a simple increase in production costs for previously dispatched units or changes in the profile of generating unit dispatch—mean increased total costs for electricity generation, compared to the pre-regulation baseline.

[131] In contrast, the social cost estimated in Section IX.C reflects the discounted value of compliance costs over the entire 51-year analysis period, as of 2013. Additionally, screening-level analyses presented in earlier sections are static analyses and do not account for interdependence of electric generating units in supplying power to the electric transmission grid. In contrast, IPM accounts for potential changes in the generation profile of steam electric and other units and consequent changes in market-level generation costs, as the electric power market responds to higher generation costs for steam electric units due to the final rule.

[132] Avoided closures may occur among facilities that incur no compliance costs under the final rule or for which compliance costs are low relative to the costs estimated for other regulated facilities.

[133] As described earlier in this preamble, under the new unit provision of the final rule, new units as defined at 125.92 include, stand-alone fossil fuel and combined cycle units. As described in Chapter 6 of the EA, the IPM analysis accounts only for compliance costs associated with new units. Further, EPA assigned these costs only to coal steam and combined cycle capacity.

slightly—by no more than $0.05 per MWh (0.1 percent) in TRE. Electricity prices increase in the remaining five NERC regions, with the largest increase, $0.29 per MWh (0.4 percent), occurring in NPCC. These very small estimated changes in electricity prices are essentially within the analytic ''noise'' of the electricity market modeling system.

At the national level, total generation costs increase by 0.3 percent of the baseline value—again, a very modest amount. Across regions, no NERC region records an increase in total costs exceeding 0.5 percent. The change in variable production costs ($/MWh)—a specific measure of the effect of the final rule on short-run electricity generation costs—is nearly zero with no NERC region recording a consequential change.

EXHIBIT IX–10—IMPACT OF THE FINAL RULE ON NATIONAL AND REGIONAL MARKETS, AT THE YEAR 2030

NERC region[a]	Total baseline capacity (GW)	Net changes in early retirements		Changes in variable costs		Changes in total costs		Changes in electricity price	
		GW	% of total baseline capacity	$2011/MWh	% of baseline	Mill 2011$	% of baseline	$2011/MWh	% of baseline
FRCC	68	0	0.30	−$0.03	−0.10	$51	0.30	−0.01	0.00
MRO	76	0	0.00	0.01	0.10	62	0.40	0.21	0.30
NPCC	73	0	0.50	0.00	0.00	28	0.20	0.29	0.40
RFC	237	0	0.10	0.01	0.00	157	0.30	0.15	0.20
SERC	274	0	0.10	0.02	0.10	182	0.30	0.08	0.10
SPP	59	−1	−1.50	0.02	0.10	31	0.30	−0.01	0.00
TRE	98	1	0.80	−0.01	0.00	48	0.30	−0.05	−0.10
WECC	220	0	0.00	0.00	0.00	9	0.00	0.03	0.00
Total ..	1,106	1	0.10	0.00	0.00	568	0.30	.....	N/A

[a] FRCC (Florida Reliability Coordinating Council), MRO (Midwest Reliability Organization), NPCC (Northeast Power Coordination Council), RFC (ReliabilityFirst Corporation), SERC (Southeastern Electricity Reliability Council), SPP (Southwest Power Pool), TRE (Texas Reliability Entity), and WECC (Western Electricity Coordinating Council).

EXHIBIT IX–11—IMPACT OF THE FINAL RULE ON NEW CAPACITY (GW), AT THE YEAR 2030

Capacity type	Baseline value	Final rule		
		Value	Difference	% Change
Coal Steam	0	0	0	NA
Combined Cycle	75	76	1	0.8
Combustion Turbine	6	6	0	0.0
Hydro	0	0	0	NA
Nuclear	0	0	0	NA
O/G Steam	0	0	0	NA
Other Non-Steam[a]	25	25	0	0.1
Other Steam[b]	9	9	0	0.0
Total	114	115	1	0.5

[a] Other non-steam capacity includes wind, solar, pumped storage, and fuel cell.
[b] Other steam capacity includes biomass, geothermal, municipal solid waste, fossil waste, landfill gas, tires, and non-fossil waste.

Impact on Regulated Facilities as a Group

EPA used the same IPM V4.10_MATS analysis results for 2030 as those used to assess market-level impacts described above; however, this analysis considers the effect of the final rule only on regulated facilities modeled in IPM (i.e., 520 facilities). For this analysis, EPA considered four output metrics: (1) Incremental capacity closures; (2) changes in capacity closures as a percent of total baseline capacity; (3) changes in total generation; and (4) changes in variable production costs per MWh.

As shown in Exhibit IX–12, for the group of regulated facilities, the impact of the final rule is overall slightly greater than that observed over all generating units in the IPM universe (i.e., market-level analysis discussed in the preceding section). This difference is due to the fact that in the electricity market as a whole, impacts on regulated facilities, which become less competitive compared to facilities that do not incur compliance costs, are offset by changes in capacity and energy production at the other electric power facilities. Nevertheless, the impact on the group of regulated facilities remains small. For instance, while there is essentially no change in total available capacity for the overall electricity market at the national level, for the group of regulated facilities, total available capacity falls by only 0.4 percent (2 GW). At the regional level, five NERC regions incur loss in total capacity, with the largest percentage loss of 2.8 percent and the largest absolute loss of 0.9 GW occurring in the NPCC region.

The 2 GW of capacity loss at regulated facilities reflects a combination of closures and avoided closures of generating units in the universe of regulated facilities. Some unit closures result in full facility closures (i.e., all generating units at a facility close), while others result in only partial facility closures (i.e., some, but not all, generating units at a facility close). For avoided closures, a generating unit projected to close in the baseline case but remains open under the policy case,

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in some instances resulting in an avoided full facility closure. Overall, 22 generating units close (4 GW) and 12 generating units avoid closure (2 GW) in the policy case, resulting in net closure of 10 generating units (approximately 2 GW) in Electricity Market Analysis—Final Rule analysis. The 22 generating unit closures reflect retirement of nine units at six full-closure facilities (2 GW) and retirement of 13 units at six partial-closure facilities (2 GW). With only one exception, these retirements involve older, less efficient generating units with very low capacity utilization rates.

At the national level, for the group of regulated facilities, total generation at regulated facilities declines by less than 2 GWh or approximately 0.1 percent of baseline generation in these facilities. The MRO and SERC regions record slight increases in generation essentially amounting to zero percent of baseline generation at regulated facilities in these regions, with the remaining five NERC regions recording a reduction in electricity generation of no more than 0.4 percent in FRCC.

Over all regulated facilities, there is essentially no change in variable production costs ($/MWh) at the national level, while at the NERC region level, the change does not exceed 0.2 percent for any of the regions. These findings of very small effects confirm EPA's assessment that the assessed capacity closures among regulated facilities are of little economic consequence at both the national and regional levels.

EXHIBIT IX–12—IMPACT OF ELECTRICITY MARKET ANALYSIS OPTIONS ON THE GROUP OF REGULATED FACILITIES, AT THE YEAR 2030

NERC region[a]	Baseline capacity (MW)	Net change in early retirements/closures		Change in generation		Change in variable production cost	
		Capacity (MW)	% of baseline	GWh	% of baseline	$2011/MWh	% of baseline
FRCC	30,794	203	0.7	−527	−0.4	−0.08	−0.2
MRO	31,747	0	0.0	30	0.0	0.01	0.1
NPCC	30,977	855	2.8	−25	0.0	0.00	0.0
RFC	126,905	223	0.2	−619	−0.1	0.00	0.0
SERC	142,840	476	0.3	3	0.0	0.02	0.1
SPP	24,487	−530	−2.2	−411	−0.3	0.01	0.0
TRE	38,378	808	2.1	−163	−0.1	−0.02	−0.1
WECC	34,788	0	0.0	−8	0.0	0.00	0.0
Total	460,917	2,035	0.4	−1,721	−0.1	0.00	0.0

[a] FRCC (Florida Reliability Coordinating Council), MRO (Midwest Reliability Organization), NPCC (Northeast Power Coordination Council), RFC (ReliabilityFirst Corporation), SERC (Southeastern Electricity Reliability Council), SPP (Southwest Power Pool), TRE (Texas Reliability Entity), and WECC (Western Electricity Coordinating Council).

Impact on Individual Regulated Facilities

Results for the group of 520 regulated facilities as a whole may mask shifts in economic performance among individual facilities incurring compliance costs under the final rule. To assess potential facility-level effects, EPA analyzed facility-specific changes between the baseline case and the final rule for the following metrics: (1) Capacity utilization (defined as annual generation (in MWh) divided by [capacity (MW) times 8,760 hours]) (2) electricity generation, and (3) variable production costs per MWh.

Exhibit XI–13 presents the estimated number of regulated facilities with specific degrees of change in operations and financial performance. Under the final rule, this analysis shows that most facilities experience only slight effects—i.e., no change or less than a 1 percent reduction or 1 percent increase. Only six facilities are estimated to incur a reduction in capacity utilization and 13 facilities a reduction in generation of at least 1 percent, with only five facilities estimated to incur an increase in variable production costs per MWh of at least 1 percent. These facilities represent approximately 1 percent of 520 regulated facilities analyzed in IPM.

EXHIBIT IX–13—IMPACT OF THE ELECTRICITY MARKET ANALYSIS—FINAL RULE ON INDIVIDUAL REGULATED FACILITIES AT THE YEAR 2030

[Number of regulated facilities with indicated effect]

Economic measures	Reduction			No Change	Increase			N/A[b c]
	≥3%	≥1 and <3%	<1%		<1%	≥1 and <3%	≥3%	
Change in Capacity Utilization[a]	1	5	45	340	35	2	0	92
Change in Generation	9	4	37	345	29	2	2	92
Change in Variable Production Costs/MWh	2	1	70	86	242	4	1	114

[a] The change in capacity utilization is the difference between the capacity utilization percentages in the baseline and policy cases. For all other measures, the change is expressed as the percentage change between the baseline and post-compliance values.

[b] Facilities with status changes in either the baseline case or the policy case were excluded from these calculations. Specifically, there are 17 full baseline facility closures, 59 partial baseline facility closures, four avoided partial facility closures, six partial policy facility closures, and six partial policy facility closures.

[c] The change in variable production cost per MWh could not be developed for 22 facilities with zero generation in either the baseline case or the policy case.

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ii. Analysis Results for 2020—To Capture the Effect of Technology-Installation Downtime

This section presents market-level results for the final rule for the 2020 IPM run year, which represents 2017 through 2024. As discussed above, this IPM run year captures the period when regulated facilities are expected to install compliance technologies under the final rule. Of particular importance as a potential impact, the additional downtime from installation of compliance technologies could manifest as increased electricity production costs resulting from the dispatch of higher-production-cost generating units during the period when units are taken offline to install compliance technologies. Because these effects are of most concern in terms of potential impact on national and regional electricity markets, this section presents results only for the overall electricity market and does not present results for the subset of regulated facilities.

As shown in Exhibit IX–14, the estimated effects of technology-installation downtime under the final rule are small. At the national level, total production costs increase by 0.4 percent. At the regional level, these costs increase in all NERC regions, with MRO and SPP recording the largest increase of 0.6 percent.

At the national level, variable production costs ($/MWh) increase by approximately 0.2 percent. While the effect on variable production costs varies across NERC regions, this effect is small overall, with the largest increase of less than 0.4 percent occurring in FRCC. While electricity prices increase in all NERC regions, the magnitude of that increase is generally small, ranging from $0.15 per MWh (0.3 percent) in MRO and WECC to $0.56 per MWh (0.9 percent) in FRCC.

EXHIBIT IX–14—SHORT-TERM EFFECT OF TECHNOLOGY INSTALLATION DOWNTIME ON NATIONAL ELECTRICITY MARKET UNDER THE FINAL RULE—2020

NERC Region [a]	Change in generation		Change in variable production cost		Change in total costs		Change in electricity price	
	2011$/MWh	% of baseline	2011$/MWh	% of baseline	Million 2011$	% of baseline	2011$/MWh	% of baseline
FRCC	−108	0.0	0.13	0.4	51	0.5	0.56	0.9
MRO	52	0.0	0.03	0.2	64	0.6	0.15	0.3
NPCC	−88	0.0	0.05	0.2	31	0.3	0.18	0.3
RFC	447	0.0	0.03	0.1	164	0.4	0.19	0.4
SERC	−369	0.0	0.04	0.1	185	0.4	0.27	0.6
SPP	−53	0.0	0.08	0.3	56	0.6	0.18	0.4
TRE	0	0.0	0.08	0.3	64	0.5	0.21	0.4
WECC	33	0.0	0.04	0.2	39	0.1	0.15	0.3
Total	−88	0.0	0.05	0.2	652	0.4		N/A

[a] FRCC (Florida Reliability Coordinating Council), MRO (Midwest Reliability Organization), NPCC (Northeast Power Coordination Council), RFC (ReliabilityFirst Corporation), SERC (Southeastern Electricity Reliability Council), SPP (Southwest Power Pool), TRE (Texas Reliability Entity), and WECC (Western Electricity Coordinating Council).

EPA recognizes any capacity outages estimated to occur in conjunction with installation of compliance technologies at existing units will require outage coordination by the system operator or other planning authority. Where possible, these outages would be scheduled in concurrence with normal scheduled maintenance outages. Permit authorities are provided flexibility to tailor compliance timelines. This flexibility will ensure that any adverse impact on local electric reliability as a result of this rule will be avoided. Facilities would receive workable construction schedules from permit writers that will allow schedule outages for installation without adversely affecting electric supply reliability.

2. Manufacturers

This section presents EPA's estimated economic impacts on manufacturers for the final rule and the other options EPA considered. These analyses assess the impact of regulatory requirements on the financial performance of regulated facilities (facility-level analysis) and the entities that own them (entity-level analysis). Similarly to the electric generators analysis, for the manufacturers facility-level and entity-level analyses, the Agency assumed that facilities would pass none of their compliance costs forward to customers as price increases, i.e., all compliance costs will be absorbed by regulated facilities and their parent entities. For details on the cost-pass-through (CPT) analysis for information on this assumption, see the EA, Appendix K. EPA developed and used sample weights to extrapolate impacts assessed initially at the level of a sample of facilities to the full population of regulated facilities. For information on the development and use of sample weights, see EA Appendix H.

a. Facility-Level Impact Analysis for Manufacturers

EPA conducted two separate facility-level analyses for manufacturers: (1) A stand-alone cost-to-revenue screener analysis and (2) a facility closure and financial stress short of closure test. For the cost-to revenue screener test, shown in Exhibit IX–15, EPA divided the after-tax, annualized compliance cost by facility-level revenue. Under the final rule, EPA found that of 500 Primary Manufacturing Industry facilities, 496 incur costs less than one percent of revenue, four incur costs between one and three percent, and none incur costs greater than 3 percent. For the nine Other Industries facilities, EPA estimated that eight facilities would incur costs less than one percent and one would incur costs between one and three percent of revenue. For Proposal Option 4, all Primary Manufacturing Industry facilities (500 facilities) and Other Industry facilities (nine facilities) incur costs less than one percent of revenue. Under Proposal Option 2, 491 Primary Manufacturing Industry facilities incur costs less than one percent and nine facilities incur costs between one and three percent, while seven Other Industry facilities incur costs less than one percent, one facility incurs costs between one and three percent, and one facility incurs costs greater than three percent.

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EXHIBIT IX–15—FACILITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS

Option	Number of facilities with a cost-to-revenue ratio of [a]		
	<1%	≥1 and <3%	≥3%
Primary manufacturing industries			
Proposal Option 4	500	0	0
Final Rule	496	4	0
Proposal Option 2	491	9	0
Other industries			
Proposal Option 4	9	0	0
Final Rule	8	1	0
Proposal Option 2	7	1	1

[a] EPA conducted this analysis for 579 facilities in the Primary Manufacturing Industries and 10 facilities in the Other Industries. Note, these facility counts and analysis exclude facilities identified as baseline closures in the severe impact analysis, which is described below.

For the second analysis, EPA assessed how compliance costs would likely affect financial performance and condition of the 509 manufacturers [134] using two measures: (1) Facility closures (severe impacts) and associated losses in revenue and employment, and (2) financial stress short of closure (moderate impacts).

For the analysis of severe impacts, EPA identified a facility as a regulatory closure if it would have operated under baseline conditions but would not be financially viable under the new regulatory requirements and the costs of the final rule leading to that finding exceeded a threshold of 0.1 percent of revenue. Specifically, the Agency examined the facility's going-concern value before and after meeting regulatory requirements. EPA used a discounted cash flow framework in which after-tax cash flow is discounted at an estimated cost of capital to calculate the going concern value of the facility.[135] In conjunction with the discounted cash flow analysis, EPA tested whether annualized costs exceeded 0.1 percent of revenue by dividing the after-tax, annualized total compliance cost by facility-level revenue. If this analysis found that the facility's business value would become negative as a result of estimated compliance costs *and* the annualized cost of compliance exceeded 0.1 percent of revenue, EPA classified the facility as a regulatory closure.

For facilities estimated not to close under the severe-impact test, EPA conducted a moderate-impact test to assess whether any would experience financial stress short of closure as the result of regulatory requirements (e.g., higher costs of capital borrowing). EPA used two financial performance measures to test for occurrence of financial stress: (1) Interest coverage ratio and (2) pre-tax return on assets. The Agency compared these measures before and after compliance with regulatory requirements against industry-specific performance thresholds for the two financial measures. If both measures for a facility exceeded the threshold in the baseline, and at least one measure fell below the threshold in the post-compliance case, EPA counted this as a moderate impact based on the rule.

Exhibit IX–16 presents the results from the severe-impact and moderate-impact analyses. EPA estimated that no facilities would be at risk of closure as a result of the final rule and that 12 facilities could experience financial stress short of closure. For Proposal Option 4, EPA also estimated no closures, while moderate impacts are significantly lower, estimated at two facilities. Under Proposal Option 2, EPA estimated that one facility would be at risk of closure, while the moderate impact finding is the same as for the final rule: 12 facilities. Again, this analysis is conducted assuming that all the costs are borne by the facility and cannot be passed along, an assumption that is highly unlikely to be true, as many of these facilities are in industries where there is some market power and barriers to entry. Thus, these tests present worst case scenario results.

EXHIBIT IX–16—FACILITY IMPACTS AND COMPLIANCE COSTS FOR MANUFACTURERS [d]

	Proposed option 4	Final rule	Proposed option 2 [c]
Primary manufacturing industries [a]			
Number of Facilities Operating in Baseline	500	500	500
Number of Closures (Severe Impacts)	0	0	1
Percentage of Facilities Closing	0%	0%	0%
Number of Facilities with Moderate Impacts	2	12	12
Percentage of Facilities with Moderate Impacts	1%	3%	3%
Other industries [b]			
Number of Facilities Operating in Baseline	9	9	9
Number of Closures (Severe Impacts)	0	0	0

[134] This is a sample-weighted estimate of the number of manufacturers, calculated using economic weights. This number excludes 70 facilities estimated to be at substantial risk of financial failure regardless of any additional financial burden that might result from the final rule or other options considered in development of this rule. For details see EA Appendix H.

[135] This after-tax cash flow analysis conducted for manufacturers is similar in concept to the cash flow analysis conducted for electric generators through the IPM analysis.

EXHIBIT IX–16—FACILITY IMPACTS AND COMPLIANCE COSTS FOR MANUFACTURERS [d]—Continued

	Proposed option 4	Final rule	Proposed option 2 [c]
Percentage of Facilities Closing	0%	0%	0%
Number of Facilities with Moderate Impacts	0	0	0
Percentage of Facilities with Moderate Impacts	0%	0%	0%

[a] Primary Manufacturing Industries include facilities in the Aluminum, Chemicals and Allied Products, Food and Kindred Products, Paper and Allied Products, Petroleum Refining, and Steel industries.
[b] Other Industries include cooling water-dependent facilities in industries whose principal operations lie in businesses other than the electric power industry or the Primary Manufacturing Industries.
[c] Under Proposal Option 2, the percentage of facilities closing is 0.3 percent.
[d] The analysis assumes no cost pass through.

b. Entity-Level Impact Analysis

EPA also examined the impact of regulatory requirements on entities that own regulated manufacturers facilities. An entity that owns multiple facilities could be adversely affected because of the cumulative burden of regulatory requirements the facilities face. For this analysis, a parent entity is the domestic parent entity with the largest ownership share in a regulated facility. For each identified parent entity, EPA aggregated facility-level, annualized, after-tax compliance costs to the level of the parent entity and compared these entity-level costs to entity-level revenue. Similarly to electric generators, EPA used cost-to-revenue thresholds of 1 and 3 percent as thresholds for categorizing levels of impacts.

EPA considered two cases, based on two sets of entity-level. These cases, which are described in the EA, Appendix H, provide a range of estimates for the number of entities incurring compliance costs and the costs incurred by any entity owning a regulated facility. EPA conducted this analysis for 509 facilities in the primary manufacturing industries and 12 facilities in other industries.[136] For information on the methodology used for the entity-level cost-to-revenue analysis, see the EA, Chapter 5.

Exhibit IX–17 presents the results from the entity-level analysis for these two cases. EPA estimated that between 120 and 337 entities own 521 regulated facilities. Under the final rule, between 90 and 95 percent of all entities are estimated to incur compliance costs of less than 1 percent of revenue. This is true also for Proposal Option 2. Under Proposal Option 4, more entities are expected to incur compliance costs of less than 1 percent of revenue (between 94 and 96 percent of all entities).

EXHIBIT IX–17—ENTITY-LEVEL COST-TO-REVENUE ANALYSIS RESULTS

Option	Not analyzed due to lack of revenue information		Number of entities with a cost-to-revenue ratio of					
			< 1%		≥ 1% and < 3%		≥ 3%	
	#	%	#	%	#	%	#	%
Case 1: Lower bound estimate of number of entities that own regulated facilities; upper bound estimate of total compliance costs that an entity may incur [b]								
Proposal Option 4	5	4	113	94	2	2	0	0
Final Rule	5	4	108	90	6	5	1	1
Proposal Option 2	5	4	108	90	6	5	1	1
Case 2: Upper bound estimate of number of entities that own regulated facilities; lower bound estimate of total compliance costs that an entity may incur [c]								
Proposal Option 4	12	4	324	96	1	[a] 0	0	0
Final Rule	12	4	319	95	6	2	0	0
Proposal Option 2	12	4	319	95	6	2	0	0

[a] The percentage of entities with impacts greater than or equal to 1 percent and less than 3 percent is less than 0.5 percent.
[b] The total number of entities under Case 1 is 120.
[c] The total number of entities under Case 2 is 337.

E. Employment Effects

To study employment effects of this rule, EPA considered the potential effects of the final rule, focusing on the impacts of meeting compliance requirements in the directly regulated industry sectors: The Electric Power Industry, and selected Primary Manufacturing Industries, including Aluminum, Chemicals and Allied Products, Food and Kindred Products, Paper and Allied Products, Petroleum Refining, and Steel Manufacturing.

When the economy is at full employment, an environmental regulation is unlikely to have much impact on net overall U.S. employment; instead, labor would primarily be shifted from one sector to another. These shifts in employment impose an opportunity cost on society, approximated by the wages of the employees, as regulation diverts workers from other activities in the economy. In this situation, any effects on net employment are likely to be transitory as workers change jobs (e.g., some workers may need to be retrained or require time to search for new jobs,

[136] This is a sample-weighted estimate of the number of manufacturer facilities, calculated using technical weights. This number excludes 67 facilities estimated to be at substantial risk of closure regardless of any additional financial burden that might result from the regulatory options under consideration.

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while shortages in some sectors or regions could bid up wages to attract workers).

On the other hand, if a regulation comes into effect during a period of high unemployment, a change in labor demand due to regulation may affect net overall U.S. employment because the labor market is not in equilibrium. Schmalansee and Stavins [137] point out that net positive employment effects are possible in the near term when the economy is at less than full employment due to the potential hiring of idle labor resources by the regulated sector to meet new requirements (e.g., to install new equipment) and new economic activity in sectors related to the regulated sector. In the longer run, the net effect on employment is more difficult to predict and will depend on the way in which the related industries respond to the regulatory requirements. As Schmalansee and Stavins note, the magnitude of the effect on employment could vary over time, region, and sector, and positive effects on employment in some regions or sectors could be offset by negative effects in other regions or sectors. For this reason, they urge caution in reporting partial employment effects because it can ''paint an inaccurate picture of net employment impacts if not placed in the broader economic context.''

In that spirit, unlike the analysis for the proposed rule, for the final rule EPA is not estimating quantitative employment impacts and instead, including only a qualitative discussion. The methods used at proposal were not sufficiently robust, largely because they relied on an input-output analysis that assumed fixed production relationships and used historical data to estimate the labor and other inputs required for compliance with the rule. Since publication of the proposed rule, EPA has concluded that input-output analysis is inappropriate for assessing employment impacts of national-level regulations. Input-output models are static, do not include prices, and assume the supply of all inputs is inexhaustible. They do not model a wide variety of adjustments that are expected to occur over time, such as changes in production processes, technology or trade patterns.[138] After reviewing the public comments EPA received on the proposed rule, the Agency concludes that the commenters have not identified any specific improvements to the employment analysis of the proposed rule. Thus, today's final rule EA includes a qualitative discussion highlighting the variety of potential adjustments in the labor market that may follow the rulemaking.

To elaborate on the difficulty of deriving high quality estimates of how environmental regulations will impact net employment, the task requires consideration of labor demand in both the regulated and environmental protection sectors, as well as labor supply more generally. Economic theory predicts that the net effect of an environmental regulation on labor demand in regulated sectors could be positive or negative; the direction of the outcome depends on the magnitude of output and substitution effects, explained further in the EA. Peer-reviewed econometric studies that use a structural approach, applicable to overall net effects in the regulated sectors, indicate that such effects, whether positive or negative, have been small and have not affected employment in the national economy in a significant way (Berman and Bui 2001, Morgenstern, Pizer and Shih 2002). Effects on labor demand in the environmental protection sector seem likely to be positive.

In aggregate, the environmental protection sector is likely to experience a temporary increase in jobs created as more compliance technology systems are designed, manufactured, and installed attributable to the final rule. In addition, because of regional variation in consumption patterns and the presence of regulated facilities and supporting industries, short- and long-run employment effects likely will vary across the United States. It is possible that positive net employment effects will occur in the near term due to the hiring of idle labor resources by the regulated sectors to plan for and meet new technology control requirements rather than diverting workers from other productive employment. However, it is also possible that in the long run, as the economy returns to full employment, any changes in employment in the regulated sectors due to the final rule will be offset by employment changes in other sectors. These dynamics compound the uncertainty in estimating employment effects for a substantial number of years into the future.

Even if regulated facilities are able to reduce the impact of regulatory requirements by changing their production processes in the post-rule environment, production costs may still be higher compared to those before the rule. As a result, regulated facilities may seek to increase their product prices in response to the higher production costs. For example, attempts by electric generators to recover increases in electricity generation costs, however small, are likely to result in higher electricity rates. The impact of this increase will vary by region, customer group (e.g., industrial, commercial, transportation, and residential), and by industry, depending on the electricity-use intensity.[139] Further, the extent to which electric generators are able to pass their costs to consumers through higher electricity rates, will vary by region. Specifically, electric generators operating in regions where electricity prices remain regulated under the traditional cost-of-service rate regulation framework may be able to recover compliance cost-based increases in increased rates.[140] However, cost recovery is less certain for electric generators operating in States where electric power generation has been deregulated, and will depend on the competitive circumstances of specifically affected facilities.

Overall, the long-run changes in employment will likely depend on how the electric power industry, primary manufacturing industries, and other industries adjust in response to the new regulatory requirements, and on the upstream and downstream effects of those adjustments on the rest of the economy, as well as the overall state of the economy and labor markets. The long-run employment effects in the directly affected sectors will depend on a number of economic factors. These factors include changes in labor requirements to operate the infrastructure in general and compliance technology in particular at regulated facilities, the potential to change production processes to become less dependent on cooling water, availability of alternative technologies to meet compliance requirements, and changes in demand for the outputs of the directly affected sectors. Because

[137] Schmalansee, Richard, and Robert N. Stavins. ''A Guide to Economic and Policy Analysis of EPA's Transport Rule.'' White paper commissioned by Exelon Corporation, March 2011 (Docket EPA–HQ–OAR–2011–0135–0054).

[138] For a discussion of input-output models see Chapter 8 of the EPA Handbook on the Benefits, Costs, and Impacts of Land Cleanup and Reuse (2011).

[139] See the EA *Chapter 6: Electricity Market Analysis* for assessment of the impacts of increased production costs on wholesale electricity prices and *Chapter 4: Economic Impact Analysis—Electric Generators* for analyses of the impacts on retail rates by customer group.

[140] However, even for electric generators operating under traditional rate regulation, the recovery of cost increases through increased rates is not certain, and will depend on additional factors such as the facility ownership structure and operating model, approval of public utility commissions, and the importance and role of market mechanisms in dispatching production of electricity across generating units. See *Chapter 2A* of the EA for additional discussion.

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these and many other interrelated factors include data and methodology limitations, it is difficult to fully assess the employment impacts of the final rule. However, based on the available evidence from several peer-reviewed econometric studies mentioned above that are applicable to net effects in the regulated sectors and that closed-cycle recirculating systems was rejected as national BTA for entrainment, EPA expects that employment impacts of today's rule are not likely to be substantial.

X. Benefits Analysis

A. Introduction

This section presents EPA's estimates of the national environmental benefits of the final existing facilities rule and other options considered by EPA. This section describes how EPA calculated values for those benefits it could monetize. EPA did not rely on the results of its stated preference survey in estimating the benefits of today's rule. It also presents descriptive information for those benefits for which EPA could not develop a monetary value. The benefits EPA assessed occur because of reductions in impingement and entrainment at cooling water intake structures affected by the rulemaking and changes in greenhouse gas emissions at regulated facilities. Impingement occurs where fish and other aquatic life are trapped on equipment as they enter the cooling water intake structure. Entrainment occurs where aquatic organisms, including eggs and larvae, are drawn into the cooling system, passed through the heat exchanger, and discharged back into the source waterbody. Impingement and entrainment kill or injure large numbers of aquatic organisms across all life stages. On the basis of entrainment data presented in facility studies, EPA assumes a mortality rate of 100 percent for entrained individuals. Mortality is then reduced on the basis of the efficiency of technology in place in reducing mortality rates, or by reducing levels of impingement and entrainment.[141] By reducing impingement mortality and entrainment, the final existing facilities rule is likely to increase the number of fish, shellfish, and other aquatic organisms in affected water bodies resulting in healthier aquatic environments. In turn, this healthier aquatic environment directly improves welfare for individuals using the affected aquatic resources, generating *use benefits* such as increases in the value of recreational and commercial fisheries or increases in property values. Reductions in impingement mortality and entrainment also improve welfare for individuals without use of the affected resources, generating *nonuse benefits,* such as improved ecosystem function and resource bequest values. Section D provides an overview of the types and sources of benefits EPA anticipated, how EPA estimated these benefits, and the level of benefits that the final rule and other options EPA considered for the rule would achieve.

EPA derived national benefit estimates for the final rule and other options considered from a series of regional studies representing a range of waterbody types and aquatic resources. Section B provides detail on the regional study design. Section C describes the impingement and entrainment effects and Section D presents the national benefits estimates.

The methodologies used to estimate benefits are largely built on those used to estimate benefits for the remanded Phase II and Phase III and the proposed existing facilities rules. In addition to updating these analyses, EPA more fully investigated the effects of impingement mortality and entrainment on T&E species, incorporated benefits from greenhouse gas reductions, and improved its estimation of nonuse benefits. The Benefits Analysis document for the final existing facilities rule (referred to as the BA) provides detailed descriptions of the new methodologies EPA used to analyze the benefits of regulatory options, and provides references to (i) Part A of the 2004 Regional Benefits Analysis for the Final Section 316(b) Phase II Rule, and (ii) Part A of the 2006 Regional Benefits Analysis Document for the Final Section 316(b) Phase III Existing Facilities Rule for analyses using similar methodologies.

The BA provides EPA's benefit estimates for the final rule and considered options. EPA relied on information collected in the 2000 section 316(b) industry surveys (the Industry Screener Questionnaire (SQ) and the Detailed Industry Questionnaire (DQ)) on cooling water systems and intake structures already in place to estimate the number of regulated facilities under regulatory options considered for the final existing facilities rule. For the analysis of regulated electric generators, EPA used information from 656 regulated electric generating facilities that responded to the section 316(b) industry surveys on cooling water systems and intake structures already in place. Because the DQs were sent to a sample of the manufacturing industries that use cooling water, the respondents were assigned sample weights designed to represent other facilities in other manufacturing industries that were not covered in the survey. All regulated facilities have a DIF of at least 2 mgd. EPA estimated regional benefits from the sample of facilities for which EPA has sufficient DQ information to estimate the environmental impacts of regulatory options. The environmental impacts from the set of explicitly analyzed facilities were then extrapolated to the universe of facilities in a region using statistical weights developed for this analysis. National benefits are estimated as the sum of the regional benefits.

As described above at Section IX, the findings presented in this section assume that all facilities with impoundments will qualify as having closed-cycle recirculating systems in the baseline. For purposes of this analysis, EPA did not estimate IM&E reductions for these facilities under the final rule and other options considered; however, these facilities remain subject to today's rule and are assigned administrative costs. To the extent that some of these facilities do not qualify as having closed-cycle cycle recirculating systems in the baseline, the monetized benefits reported in this section may be underestimated. EPA notes that the vast majority of these facilities occur in the Inland benefits region. Any underestimation in monetized benefits due to the treatment of facilities with impoundments is likely to be minor because commercial fishing benefits and nonuse benefits are not estimated for the Inland region.

B. Regional Study Design

EPA evaluated the benefits of today's rule in seven study regions.[142] Regions were defined on the basis of ecological similarities within regions (e.g., freshwater versus marine, similar communities of aquatic species), and on characteristics of commercial and recreational fishing activities. The seven study regions are: California,[143] North Atlantic, Mid Atlantic, South Atlantic, Gulf of Mexico, Great Lakes, and Inland. The five coastal regions EPA identified (California, North Atlantic, Mid-Atlantic, South Atlantic, and Gulf of Mexico) correspond to those of the

[141] See the discussion in Section III on entrainment mortality data and assumptions.

[142] Benefits associated with changes in greenhouse gas emissions were estimated for the nation as whole.

[143] The California region includes facilities in State of California and four facilities in Hawaii. No coastal facilities are in Oregon, and one facility in Washington is classified as a baseline closure.

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National Oceanic and Atmospheric Administration's National Marine Fisheries Service. The Great Lakes region includes Lake Ontario, Lake Erie, Lake Huron (including Lake St. Clair), Lake Michigan, Lake Superior, and the connecting channels (Saint Mary's River, Saint Clair River, Detroit River, Niagara River, and Saint Lawrence River to the Canadian border) as defined in 33 U.S.C. 1268, Sec. 118(a)(3)(b). The Inland region includes all remaining facilities that withdraw water from freshwater lakes, rivers, and reservoirs, including inland facilities in coastal states. Notably, of the 435 facilities that are on freshwater streams or rivers, 30 percent (132) have average actual intake flow that is greater than 5 percent of the mean annual flow of the source waters, which is a significant amount of the source water flow. During periods of low river flow, or during periods of higher than average withdrawals of cooling water, the proportionate withdrawal of source waters could be much higher. Thus, the potential for adverse environmental impacts could increase dramatically during these periods. The number and total operational intake flow of all 316(b) facilities by study region are presented in Exhibit X–1.

EXHIBIT X–1—NUMBER OF SURVEYED FACILITIES AND TOTAL MEAN OPERATIONAL FLOW, BY REGION

Region	Number of surveyed facilities [a]	Flow (billions of gallons per day)		
		Non-recirculating facilities [b]	Recirculating facilities	Total flow
California [c]	21	10.65	0.00	10.65
Great Lakes	50	16.24	0.24	16.47
Inland [d]	566	107.56	18.06	125.62
Mid-Atlantic	46	24.69	0.07	24.76
Gulf of Mexico	22	10.14	0.05	10.18
North Atlantic	21	5.93	0.00	5.93
South Atlantic	12	5.91	0.05	5.96
All Regions	738	181.12	18.46	199.58

[a] This table presents unweighted facility counts and flow for surveyed facilities (excluding baseline closures). The regional study design for the benefits analysis uses weights based on flow rather than facility counts. EPA did not develop weighted facility counts by benefits region. The ''All Regions'' total of 738 surveyed facilities includes 532 electric generating facilities and 206 manufacturing facilities, excluding baseline closures. The total (weighted) estimated universe of facilities, excluding baseline closures, is 1,065 facilities.

[b] Recirculating facilities are facilities with closed-cycle cooling or impoundments that qualify as closed-cycle cooling. Non-recirculating facilities include facilities with CWIS classified as once-through.

[c] The California region includes four facilities in Hawaii. There are no coastal facilities in Oregon and the one coastal facility in Washington is classified as a baseline closure.

[d] A facility in Texas has intakes in both the Inland and Gulf of Mexico regions. It is included in the Inland region in the table to prevent the double counting of facilities.

EPA obtained estimates of regional impingement mortality and entrainment by extrapolating impingement mortality and entrainment observed at 98 facilities with impingement and entrainment studies (model facilities) to all regulated facilities in the same region. EPA used regional estimates to more accurately estimate impacts by accounting for differences in ecosystems, aquatic species, and characteristics of commercial and recreational fishing activities across regions. Extrapolation was conducted on the basis of AIF reported for the period 1996–1998 by facilities in response to EPA's Section 316(b) Detailed Questionnaire and Short Technical Questionnaire. Chapter 3 of the BA provides details of the extrapolation procedure. Because the goal of the analysis was to provide estimates of impingement mortality and entrainment at regional and national scales, EPA recognizes that these averages may not reflect the substantial variability at individual facilities. In spite of this variability, EPA determined that this extrapolation is a reasonable basis for developing estimates of regional- and national-level benefits for the purposes of the final existing facilities rule.

C. Physical Impacts of Impingement Mortality and Entrainment

EPA based the benefits analysis on facility-provided impingement mortality and entrainment monitoring data. Facility data consist of records of impinged and entrained organisms sampled at intake structures and include organisms of all ages and life stages. Sampling protocols were not standardized across facilities. Facility protocols differed in sampling methods and equipment used, the number of samples taken, sampling duration, and the unit of time and volume of intake flow used to express impingement mortality and entrainment. To standardize estimates across facilities, EPA converted sampling counts into annual impingement mortality and entrainment. Using standard fishery modeling techniques,[144] EPA constructed models that combined facility-derived impingement mortality and entrainment counts with life history data from the scientific literature to derive annual estimates of the following:

- Individuals—the number of individual organisms impinged and entrained by facility intakes. Under this metric, eggs, larvae, juvenile, and adult organisms are counted as equivalent individuals.

[144] Ricker, W.E. 1975. Computation and interpretation of biological statistics of fish populations. Fisheries Research Board of Canada, Bulletin 191; Hilborn, R. and C.J. Walters. 1992. Quantitative Fisheries Stock Assessment, Choice, Dynamics and Uncertainty. Chapman and Hall, London and New York; Quinn, T.J., II. and R.B. Deriso. 1999. Quantitative Fish Dynamics. Oxford University Press, Oxford and New York; Dixon, D.A. 1999. Catalog of Assessment Methods for Evaluating the Effects of Power Plant Operations on Aquatic Communities. Electric Power Research Institute (EPRI) Final Report. Report number TR–112013.

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• A1Es (age-one equivalent losses)—the number of individual organisms of different ages impinged and entrained by facility intakes, standardized to equivalent numbers of 1-year-old fish. A conversion rate between all life history stages and age 1 is calculated using species-specific survival tables based on life history schedule and age-specific mortality rates. An individual younger than age 1 is a fraction of an age-one equivalent; an individual older than age 1 represents more than one age-one equivalent. EPA finds it appropriate to use the A1E measure because information in the record indicates that an overwhelming majority of eggs, larvae and juveniles do not survive into adulthood and the A1E calculations adjust for differences in survivorship based on species and age-specific mortality rates. EPA recognizes that using A1Es simplifies a complex ecological situation, because some of the smaller fish would provide an ecological benefit to other species as food even if they would not survive to adulthood. Recognizing this as one nonmonetized benefit in the analysis, using an A1E approach is the most reasonable approach available because to date, there is insufficient data to account for the extent to which organisms that do not survive to adulthood provide a benefit to other organisms which can be reliably monetized.

• Forgone fishery yield—pounds of commercial fish harvest and numbers of recreational fish and shellfish that are not harvested because of impingement mortality and entrainment. EPA used the Thompson-Bell equilibrium yield model [145] to convert impingement mortality and entrainment to forgone fishery yield, assuming that (1) impingement mortality and entrainment reduces the future yield of harvested adults, and (2) reductions in impingement mortality and entrainment rates will lead to an increase in harvested biomass. The general procedure involves multiplying age-specific harvest rates by age-specific weights to calculate an age-specific expected yield.

• Biomass production forgone—biomass that would have been produced had individuals not been impinged or entrained,[146] calculated for all species from species- and age-specific growth rates and survival probabilities. It refers to the mass of impinged and entrained organisms that would have served as valuable components of aquatic food webs, particularly as an important food supply to other aquatic species.

Estimates of forgone fishery yield include direct and indirect losses of impinged and entrained species that are harvested. Indirect losses represent the yield of harvested species lost because of reductions in prey availability according to a simple trophic transfer model (i.e., forage species).[147] Chapter 3 of the BA contains detailed methodology for these analyses.

Studies from individual facilities may underestimate or overestimate impingement mortality and entrainment rates at those facilities. For example, facility studies typically focus on a subset of fish species affected by impingement mortality and entrainment, resulting in other species being ignored. The number of individuals lost to impingement mortality and entrainment is then underestimated. Estimating the magnitude of this underestimate is not possible because of the low number of replicate studies. Moreover, studies often do not count early life stages of organisms that are more difficult to identify. In addition, many of the impingement mortality and entrainment studies used by the Agency were conducted more than 30 years ago, prior to the improvement of aquatic conditions that have resulted from implementation of the CWA as well as State and local laws and efforts. In locations where water quality was degraded at the time of impingement mortality and entrainment sampling relative to current conditions, the abundance and diversity of fish populations might have been depressed, resulting in low impingement mortality and entrainment estimates. Therefore, use of these data may underestimate the magnitude of current impingement mortality and entrainment. Alternatively, studies could have been conducted in locations where local fish populations are now lower than they were when the study occurred. Such a shift in fish populations might have occurred because of natural variability in populations, because of other anthropogenic effects (i.e., over-harvesting), or because of competition from invasive species. In such cases, the use of these data may overestimate the magnitude of current impingement mortality and entrainment.

EPA's use of linear methods for projecting losses to fish and shellfish in the waterbody may also overstate or understate impacts. Nevertheless, the data from facility studies are the best means to estimate the relative magnitude of impingement mortality and entrainment nationwide. Exhibit X–2 presents EPA's estimates of baseline annual impingement mortality and entrainment, and reductions in annual impingement mortality and entrainment estimated to occur under the final rule and other options considered. Impingement mortality and entrainment reductions under the final rule are less than the reductions under Proposal Option 2 and greater than reductions under Proposal Option 4. Unlike the analysis of Proposal Option 2, EPA did not model the entrainment reductions from cooling tower installation under the final rule and Proposal Option 4 because these would be based on site-specific determinations of BTA, which are not possible to predict with information EPA has today. EPA estimated a small amount of entrainment losses under the final rule and Proposal Option 4 due to the assumed installation of variable speed pumps at some facilities to achieve compliance via the low velocity compliance alternative.

[145] Ricker, W.E. 1975. Computation and interpretation of biological statistics of fish populations. Fisheries Research Board of Canada, Bulletin 191.

[146] Rago, P.J. 1984. Production forgone: An alternative method for assessing the consequences of fish entrainment and impingement losses at power plants and other water intakes. Ecological Modeling, 24(1–2): 79–111.

[147] Indirect losses account for about 10 percent of commercial and recreational harvest reductions at baseline.

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EXHIBIT X–2—BASELINE ANNUAL IM&E AND ANNUAL REDUCTIONS IN IM&E FOR EXISTING UNITS AT ALL FACILITIES SUBJECT TO THE FINAL RULE

Loss mode [a]	Reduction in annual IM&E by regulatory option [b c]			Baseline annual IM&E
	Proposal option 4	Final rule—existing units	Proposal option 2	
Individuals (millions)				
IM	419.9	441.3	511.9	568.6
E	399.8	1,693.9	335,447.6	497,316.3
IM&E	819.7	2,135.2	335,959.4	497,884.8
Age-One Equivalents (millions)				
IM	612.8	647.5	748.2	824.2
E	1.4	4.5	889.3	1,106.7
IM&E	614.2	652.0	1,637.5	1,931.0
Forgone Fishery Yield (million lbs)				
IM	12.6	13.3	15.4	16.9
E	0.0	0.1	35.7	52.9
IM&E	12.6	13.4	51.1	69.8
Production Forgone (million lbs)				
IM	129.7	136.5	157.2	174.8
E	0.5	2.4	337.0	451.8
IM&E	130.3	138.9	494.2	626.6

[a] IM = impingement mortality; E = entrainment; IM&E = impingement mortality and entrainment.
[b] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.
[c] The totals presented here do not include IM&E reductions associated with new units. Estimated IM&E reductions associated with the new unit provision of the final rule are presented in Exhibit X–4.

Exhibit X–3 presents EPA's estimates of annual impingement mortality and entrainment for final rule and other considered options by category of fish species. Estimates of annual forgone fishery yield include both direct losses of harvested species and indirect losses from reductions in prey fish species. Organisms convert (on average) only about 10 percent of the mass of food they consume into additional tissue mass. Thus, although essential to maintain ecosystem function, the vast majority of biomass moving through food webs does not reach higher trophic levels associated with commercial and recreational species and harvest. Instead, the biomass of prey species is metabolized and used for predator locomotion, reproduction, and tissue repair. Accordingly, the portion of impingement mortality and entrainment that are counted within the forgone harvest metric represent only a small percentage of all organisms experiencing impingement mortality and entrainment at cooling water intake structures. Neither forage species nor the unlanded portion of recreational and commercial species were assigned direct use values in this analysis, although losses in forage species did contribute to the overall losses in recreational and commercial species as noted above. Because the majority of annual impingement mortality and entrainment include unharvested recreational and commercial fish and forage fish, considering nonuse values in the final rule benefits analysis is particularly important. If nonuse values were not considered at all, only two to three percent of fish losses would be represented in monetized benefits.

EXHIBIT X–3—DISTRIBUTION OF ANNUAL BASELINE IM&E AND REDUCTIONS IN IM&E BY SPECIES CATEGORY, FOR INDIVIDUAL ORGANISMS AND AGE-1 EQUIVALENTS, AT EXISTING UNITS FOR THE FINAL RULE AND OPTIONS CONSIDERED

IM&E Metric [a]	Reduction in IM&E by regulatory option [b c]			Baseline IM&E
	Proposal option 4	Final rule—existing units	Proposal option 2	
Individuals (millions)				
All Species	819.7	2,135.2	335,959.4	497,884.8
Forage Species	607.9	1,423.6	224,323.1	325,069.1
Commercial & Recreational Species	211.8	711.5	111,636.3	172,815.8
Commercial & Recreational Harvest (millions of fish)	16.1	17.1	44.7	54.0
Lost Individuals with Direct Use Value (%)	1.97%	0.80%	0.01%	0.01%
Age-One Equivalents (millions)				
All Species	614.2	652.0	1,637.5	1,931.0

EXHIBIT X–3—DISTRIBUTION OF ANNUAL BASELINE IM&E AND REDUCTIONS IN IM&E BY SPECIES CATEGORY, FOR INDIVIDUAL ORGANISMS AND AGE-1 EQUIVALENTS, AT EXISTING UNITS FOR THE FINAL RULE AND OPTIONS CONSIDERED—Continued

IM&E Metric [a]	Reduction in IM&E by regulatory option [b c]			Baseline IM&E
	Proposal option 4	Final rule—existing units	Proposal option 2	
Forage Species	528.2	560.8	1,258.7	1,459.7
Commercial & Recreational Species	85.9	91.2	378.8	471.3
Commercial & Recreational Harvest (millions of fish)	16.1	17.1	44.7	54.0
A1E Losses with Direct Use Value (%)	2.63%	2.62%	2.73%	2.80%

[a] IM&E = impingement and entrainment; A1E= age-one equivalent;
[b] IM&E Effects by Option: Proposal Option 2 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.
[c] The totals presented here do not include IM&E reductions associated with new units. Estimated IM&E reductions associated with the new unit provision of the final rule are presented in Exhibit X–4.

In addition to the final rule and other options analyzed for existing units (Proposal Option 4 and Proposal Option 2), EPA analyzed requirements for new units at existing facilities. EPA's new unit provision in the final rule establishes entrainment requirements for all new stand-alone units at existing facilities. EPA could not directly apply the extrapolation methodology used for existing units because facility-specific information was not available for new units. Instead, EPA estimated impingement mortality and entrainment reductions on the basis of impingement mortality and entrainment reductions per million gallons per day from the analysis of existing units. The estimated reduction in impingement mortality and entrainment for the new unit requirement is summarized in Exhibit X–4.

EXHIBIT X–4—ANNUAL REDUCTIONS IN IM&E BY SPECIES CATEGORY FOR THE FINAL RULE FOR NEW UNITS

IM&E metric [a]	Reduction in IM&E [b]
Individuals (millions)	
All Species	867.2
Forage Species	566.1
Commercial and Recreational Species	301.1
Commercial and Recreational Harvest (millions of fish)	0.1
Lost Individuals with Direct Use Value (%)	0.01%
Age-One Equivalents (millions)	
All Species	2.3
Forage Species	1.7
Commercial and Recreational Species	0.7
Commercial and Recreational Harvest (millions of fish)	0.1
A1E Losses with Direct Use Value (%)	2.87%

[a] A1E = age-one equivalent; IM&E = impingement mortality and entrainment.
[b] Impingement mortality and entrainment reductions increase throughout the compliance period. The values presented here reflect the peak reductions achieved in 2059, the final year of the compliance period.
IM&E Effects: Entrainment requirements for all stand-alone or units.

D. National Benefits of the Final Rule and Options Considered

1. Overview

Economic benefits of the final rule and other options considered for regulated facilities can be categorized broadly into use and nonuse benefits of goods and services. Use values include benefits that pertain to the human use (direct or indirect) of affected fishery resources. Use values reflect the value of all current direct and indirect uses of a good or service. Direct use benefits can be further categorized according to whether affected goods and services are traded in the market (i.e. commercially captured fish are traded, recreational catch is not). Likewise, indirect use benefits can be linked to direct goods and services. For example, reductions in impingement mortality and entrainment of forage fish will enhance the biomass of species targeted for commercial (market) and recreational (nonmarket) uses. It could also affect property values.

Nonuse benefits are those benefits that are independent of any current or anticipated human use of a resource. Nonuse benefits reflect human values associated with existence and bequest motives. In other words, these values reflect the value the public places on something simply as a result of its existence or natural functioning. EPA estimated the economic benefits from national regulatory options using a range of valuation methods. Commercial fishery benefits were valued using market data. Recreational angling benefits were valued using a benefits transfer approach based on revealed and stated preference data. To estimate indirect use benefits from reduced impingement mortality and entrainment of forage species, EPA used a simple

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trophic transfer model. This model translated changes in impingement mortality and entrainment of forage fish into changes in the harvest of commercial and recreational species. All benefits for fish saved under today's final rule are estimates on the basis of projected numbers of age-one equivalent fish, converted to harvestable age equivalents on a species-by-species basis for those commercial species analyzed.

EPA calculated the monetary value of use benefits of the final rule and other options considered for existing facilities using two discount rate values: 3 and 7 percent. All dollar values presented are in 2011 dollars. Because avoided fish deaths occur mainly in fish that are younger than harvestable age (eggs, larvae, and juveniles), the main benefits from avoided impingement mortality and entrainment would be realized typically 3 to 4 years after their avoided death. A detailed description of the approaches used to address this is in Appendix C of the BA.

Neither forage species nor the unlanded portion of recreational and commercial species were assigned direct use values in this analysis. Their potential value to the public is derived from several alternative sources: Their indirect use as both food and breeding population for those fish that are harvested; and nonuse value. The nonuse value includes individuals' WTP (willingness to pay) for the protection of fish based on a sense of altruism, stewardship, bequest, or vicarious consumption; and their support of ecosystem stability and function. To estimate a subset of nonuse benefits from reducing impingement mortality and entrainment of forage species and unlanded commercial and recreational species, EPA conducted a benefits transfer using a nonmarket valuation study of aquatic ecosystem improvements. This effort generated partial estimates of nonuse values for resource changes for a species that represents less than one percent of adverse environmental impacts.

EPA developed and fielded an original stated preference survey to estimate total WTP for improvements to fishery resources affected by impingement mortality and entrainment from regulated 316(b) facilities (75 FR 42438, July 21, 2010). Preliminary results of the stated preference survey were described in a Notice of Data Availability (77 FR 34927, June 12, 2012). EPA presents preliminary benefits estimates based on the stated preference survey in the BA to demonstrate progress on this effort. In the absence of final survey results, EPA estimated partial nonuse benefits for the final rule using the benefits transfer approach from proposal. EPA updated the proposal results to incorporate additional stock assessment data for winter flounder, the species used as the basis for the analysis. Due to the challenges associated with estimating nonuse benefits, some nonuse benefits are described only qualitatively.

2. Timing of Benefits

Discounting refers to the economic conversion of future benefits and costs to their present values, accounting for the fact that individuals value future outcomes less than comparable near-term outcomes. Discounting enables a valid comparison of benefits and costs that occur across different periods. EPA used discounting to account for differences in the timing across benefits and costs under the final rule and options considered. EPA estimated the expected benefits of the final rule once the rule takes full effect, then used discounting to account for delays in the realization of benefits. Two different delays affect the timing of benefits under the final rule and options considered.

First, facilities will begin to incur costs prior to technology installation. Facilities will face regulatory requirements once the rule is effective, but it will take time for requirements to be developed and for the required technology to be installed. Analyzed facilities are assigned a technology installation year which considers facility characteristics and technology being installed. EPA assumed that facilities installing impingement technology tend to complete technology installation sooner than facilities installing closed-cycle cooling (for other options considered). The assignment of technology installation years is speculative on EPA's part, because EPA does not have sufficient data on hand to project the schedules that Directors will set for facilities. See Chapter 3 of the EA document for the final existing facilities rule for details on EPA's development of technology installation years. EPA effectively discounts benefits to a greater extent than costs to account for the lag between the incurrence of costs and the realization of benefits.

Second, an additional time lag will result between technology implementation and use values via increased fishery yields. This lag occurs because several years could pass between the time an organism is spared from impingement mortality or entrainment and the time of its potential harvest. For example, a larval fish spared from entrainment (in effect, at age 0) could be caught by a recreational angler at age 3, meaning that a 3-year time lag arises between the incurred technology cost and the realization of the estimated recreational benefit. Likewise, if a 1-year-old fish is spared from impingement and is then harvested by a commercial waterman at age 2, there is a 1-year lag between the incurred cost and the subsequent commercial fishery benefit. To account for this growth period, EPA applied discounting by species groups in each regional study. Note that nonuse values (depending on how they are measured) do not necessarily need to be discounted similarly.

3. Recreational Fishing Valuation

a. Recreational Fishery Methods

To estimate recreational benefits of the final options, EPA developed a benefits transfer approach on the basis of a meta-analysis of recreational fishing valuation studies designed to measure the various factors that determine WTP for catching an additional fish per trip. Regional benefits are summarized as follows (for details, see Chapter 7 of the BA):

1. Estimate the annual forgone catch of recreational fish (number of fish) attributable to impingement mortality and entrainment under current conditions.

2. Estimate the marginal value per fish using a benefit transfer function based on a meta-analysis of recreational fishing studies.

3. Multiply the forgone catch by the marginal value per fish to estimate the total annual value of the forgone catch.

4. Estimate the annual value of reductions in the forgone catch attributable to the regulatory analysis options.

5. Discount the time path of benefits at 3 and 7 percent to reflect the time lag between impingement mortality and entrainment reductions and increased harvests.

b. Estimated Benefits to Recreational Anglers

Decreasing impingement mortality and entrainment increases the number of fish available to be caught by recreational anglers, thereby increasing angler welfare. Exhibit X–5 shows the estimated benefits resulting from reduced impingement mortality and entrainment under today's final existing facilities rule and other options that EPA considered. The total annualized recreational fishing benefits for all regions at existing units of existing facilities for the final rule (impingement mortality and entrainment combined)

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are $18 million using a 3 percent discount rate and $14 million using a 7 percent discount rate. Annual recreational fishing benefits for other options considered range from $17 to $43 million using a 3 percent discount rate and $13 million to $30 million using a 7 percent discount rate.

EXHIBIT X–5—ANNUAL RECREATIONAL FISHING BENEFITS FROM ELIMINATING OR REDUCING IM&E AT EXISTING UNITS AT EXISTING FACILITIES FOR THE FINAL RULE AND OTHER OPTIONS CONSIDERED

Regulatory option [a]	Increased harvest (million fish)	3% discount rate (million 2011$)	7% discount rate (million 2011$)
Proposal Option 4	6.1	17.1	12.6
Final Rule—Existing Units	6.5	18.2	13.5
Proposal Option 2	20.5	43.0	29.5
Baseline	25.3	78.8	72.0

[a] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.

4. Commercial Fishing Valuation

Reductions in impingement mortality and entrainment at cooling water intake structures are expected to benefit the commercial fishing industry. By reducing the number of fish killed, the number of fish available for harvest is expected to increase. The next section summarizes the methods EPA used to estimate benefits to the commercial fishing sector. The section after that presents the estimated value of commercial fishing benefits.

a. Commercial Fishing Valuation Methods

The total loss to the economy from impingement mortality and entrainment impacts on commercially harvested fish species is determined by the sum of changes in both producer and consumer surplus. EPA assumed a linear relationship between stock and harvest, such that if 10 percent of the current commercially targeted stock were harvested, 10 percent of the commercially targeted fish lost to impingement mortality and entrainment would have been harvested absent impingement mortality and entrainment. The percentage of fish harvested is based on data of historical fishing mortality rates.

Producer surplus provides an estimate of the economic damages to commercial fishers, but welfare changes can also be expected to accrue to final consumers of fish and to commercial consumers (including processors, wholesalers, retailers, and middlemen) if the projected increase in harvest is accompanied by a change in price. The analysis of market impacts involves the following steps (for details, see Chapter 6 of the BA):

1. Assessing the net welfare changes for fish consumers due to changes in fish harvest and the corresponding change in fish price.

2. Assessing net welfare changes for fish harvesters due to the change in total revenue, which could be positive or negative.

3. Calculating the increase in net social benefits when the fish harvest changes by combining the welfare changes for consumers and harvesters.

For a more detailed description of the methodology for commercial fishing, see Chapter 6 of the BA.

b. Commercial Fishing Valuation Results

Exhibit X–6 presents the estimated annual commercial fishing benefits attributable to the proposed options. The results reported include the total reduction in losses in pounds of fish, and the value of this reduction discounted at 3 and 7 percent. Total estimated annualized commercial fishing benefits for the United States for the final rule are $0.9 million using a 3 percent discount rate and $0.7 million using a 7 percent discount rate. Annual commercial fishing benefits for other options considered range from $0.9 million to $3.9 million using a 3 percent discount rate and $0.7 million to $2.7 million using a 7 percent discount rate. EPA estimated the expected price changes from eliminating baseline levels of impingement mortality and entrainment and found them to be small, ranging from 0.2 to 2.5 percent.

EXHIBIT X–6—ANNUAL COMMERCIAL FISHING BENEFITS FROM ELIMINATING OR REDUCING IM&E AT EXISTING UNITS AT EXISTING FACILITIES FOR THE FINAL RULE AND OTHER OPTIONS CONSIDERED

Regulatory option [a]	Increased harvest (million lbs)	3% discount rate (million 2011$)	7% discount rate (million 2011$)
Proposal Option 4	5.3	0.9	0.7
Final Rule—Existing Units	5.7	0.9	0.7
Proposal Option 2	14.0	3.9	2.7
Baseline	17.3	8.0	7.2

[a] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.

5. Nonuse Benefits

Aquatic organisms with no direct use benefits account for the majority of cooling water intake structure losses (Exhibit X–3). Although many individuals may not use a particular waterbody for recreation or fishing, individuals nevertheless may value improvements in that waterbody. To quantitatively assess the ecological gains from the final rule and other options considered, EPA took both of the only two approaches available for quantifying nonuse benefits—a benefits transfer approach and a stated

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preference survey. It is not necessary to use a stated preference survey approach to calculate benefits; however, important nonuse benefits can be missed by not using a stated preference survey approach. So EPA took both approaches, but relied on only the benefits transfer approach for the benefits analysis supporting the final rule. The benefits transfer approach relies on the existence of previously published studies with values that can be transferred; in instances where nonuse is potentially significant, as is the case here, previously published studies would only include nonuse value if they adopted a stated preference approach.

EPA used a benefit transfer approach to partially monetize nonuse benefits associated with reductions in impingement mortality and entrainment of fish, shellfish, and other aquatic organisms under the regulatory options for the North Atlantic and Mid-Atlantic benefits regions. EPA applied estimated values from a study conducted in Rhode Island; these estimates are likely to be more representative of nonuse values held by individuals residing in the Northeast United States and less accurate in other regions. EPA was unable to identify comparable studies conducted in other regions that could be used to estimate nonuse values. Chapter 8 of the BA provides further detail on this analysis.

The preferred techniques used to estimate total values (including both use and nonuse values), in general, are benefits transfer or to conduct a stated preference survey. There are many studies in the environmental economics literature that quantify benefits or WTP associated with various types of water quality and aquatic habitat changes. However, none of these studies allows the isolation of non-market WTP associated with quantified reductions in impingement mortality and entrainment for forage fish or unlanded portion of commercial and recreational species.

a. Nonuse Benefits Transfer

EPA identified a recent stated preference survey of Rhode Island residents that is closely related to the 316(b) policy context. The study results have been published in multiple scientific journals and books including Johnston et al.[148] and Zhao et al.[149] Both the Rhode Island study and the present context address policy changes that increase the number of forage fish in aquatic habitat with unknown effects on overall fish populations. The Rhode Island study was developed originally as a case study addressing Rhode Island residents' preferences for the restoration of migratory fish passage over dams in Rhode Island's Pawtuxet and Wood-Pawcatuck watersheds. It estimates nonuse values by asking respondents to consider changes in ecological indicators reflecting quantity of habitat, abundance of wildlife, ecological condition, and abundance of migratory fish species. Within this study, estimated values were based on the relative change in abundance of fish species most affected by restoration.

Estimating benefit functions from the Rhode Island choice experiment survey[150] allows one to distinguish benefits associated with resource uses from those associated primarily with nonuse motives. Within the benefit transfer application, WTP is quantified for increases in non-harvested fish alone on the basis of the implicit price for migratory fish changes. This transfer holds constant all effects related to identifiable human uses (e.g., effects on catchable fish, public access, and observable wildlife). The remaining welfare effect—derived purely from effects on forage fish with little or no direct human use—may therefore be most accurately characterized as a nonuse benefit realized by households.

The estimation of nonuse values involved the following steps:

1. Use a model published by Zhao et al.[151] to estimate household WTP per percent increase in the number of fish in a given watershed. The household WTP values reflect a survey version that characterizes effects on the number of migratory fish passing upstream.

2. Calculate the relative change in abundance for the fish species most affected by the regulation. The structure of the transfer study dictates that WTP should be evaluated based on the single species that would experience the greatest relative increase in abundance from restoration and that WTP estimates from multiple species impacted by IM&E should not be treated as strictly additive. After reviewing available stock assessment data, current stock size, and the magnitude of IM&E, EPA determined winter flounder to be the species likely to experience the greatest percent increase in abundance among those species with sufficient stock information to conduct the analysis within the boundaries of the North Atlantic and Mid-Atlantic benefits regions. This species is harvested; however, early life stages of recreational and commercial species may be eaten by other organisms and therefore have nonuse values.

3. Estimate total household WTP by applying model results for WTP per percentage of estimated winter flounder impingement mortality and entrainment. Total regional WTP is the product of household WTP and the number of households in the affected region (for details, see Chapter 8 of the BA).

b. Estimated Nonuse Benefits for the North Atlantic and Mid-Atlantic Regions

EPA expects that a decrease in impingement mortality and entrainment will lead to increased fish abundance in affected water bodies, thus increasing nonuse benefits. Exhibit X–7 shows the benefits that would result from reducing impingement mortality and entrainment through today's final rule and other options considered. Application of the transfer study requires that the increases be expressed as a percent improvement relative to a maximum number of fish that could be supported. EPA calculated estimates of WTP on the basis of the increase in age-1 equivalent winter flounder relative to the estimated number of age-1 fish when the stock is at maximum sustainable yield, thus assuming that the population structure of the current stock is similar to the larger stock. The total annualized nonuse benefits for the North Atlantic and Mid-Atlantic regions for the existing unit provision of the final rule are $1 million using a 3 percent discount rate and $0.8 million using a 7 percent discount rate. For other options considered, annualized nonuse benefits range from $0.3 to $51 million using a 3 percent discount rate and $0.3 to $37 million using a 7 percent discount rate.

[148] Johnston, R.J., E.T. Schultz, E.T., K. Segerson, E.Y. Besedin, and M. Ramachandran. 2012. Enhancing the content validity of stated preference valuation: The structure and function of ecological indicators. Land Economics, 1: 102–120.

[149] Zhao, M., Johnson, R.J. and Schultz, E.T. 2013. What to Value and How? Ecological Indicator Choices in Stated Preference Valuation. Environmental Resource Economics. Published online, February 8, 2013.

[150] Johnston, R.J., E.T. Schultz, E.T., K. Segerson, E.Y. Besedin, and M. Ramachandran. 2012. Enhancing the content validity of stated preference valuation: The structure and function of ecological indicators. Land Economics, 1: 102–120; Zhao, M., Johnson, R.J. and Schultz, E.T. 2013. What to Value and How? Ecological Indicator Choices in Stated Preference Valuation. Environmental Resource Economics. Published online, February 8, 2013.

[151] Op cit.

EXHIBIT X–7—ANNUAL NONUSE BENEFITS FROM ELIMINATING OR REDUCING IM&E AT EXISTING UNITS AT EXISTING FACILITIES IN THE NORTH ATLANTIC AND MID-ATLANTIC REGIONS FOR THE FINAL RULE AND OPTIONS CONSIDERED [a]

Regulatory option [b]	Winter flounder IM&E (million A1E)	Increased winter flounder A1E abundance (%)	3% discount rate (millions 2011$)	7% discount rate (millions 2011$)
Proposal Option 4	0.03	0.02	0.3	0.3
Final Rule—Existing Units	0.08	0.07	1.0	0.8
Proposal Option 2	4.78	4.18	51.1	37.3
Baseline	6.23	5.44	99.1	96.9

[a] IM&E = impingement and entrainment; A1E = age-one equivalent.
[b] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.

c. Stated Preference Survey

EPA conducted a stated preference survey to calculate benefits associated with minimizing adverse impacts to aquatic ecosystems from cooling water intakes. Refer to Sections VI.F.1 and X.D.1 for additional discussion of the stated preference survey. EPA did not rely on the results of its stated preference survey in estimating the benefits of today's rule.

6. Threatened and Endangered Species

This section summarizes methods and results of EPA's analysis of benefits from improved protection of T&E species from today's final rule and options considered. Chapter 5 of the BA provides further detail on this analysis.

Even if levels of mortality due to impingement and entrainment from cooling water intake structures of T&E species are low in absolute numbers, they may represent a substantial portion of annual reproduction because of the reduced population levels that cause a species to be protected. Consequently, impingement mortality and entrainment may either lengthen recovery time, or hasten the demise of these species. Adverse effects of cooling water intake structures on T&E species can occur in several ways:

- Populations of T&E species may suffer direct harm as a consequence of impingement mortality and entrainment.
- T&E species may suffer indirect harm if a cooling water intake structure alters food webs.
- Cooling water intake structures can alter habitat designated as critical to the long-term survival of T&E species.

Consequently, the 316(b) regulation will help preserve threatened and endangered species.

a. Qualitative Assessment of Impingement Mortality and Entrainment Impacts on T&E Species

By definition, T&E species are characterized by low population levels. As such, it is unlikely that these species are recorded in significant number, if recorded at all, in impingement mortality and entrainment monitoring studies. Thus, losses are difficult to identify and quantify in a framework developed for non-listed species. Consequently, EPA developed a qualitative methodology to estimate the number of T&E species affected by impingement mortality and entrainment.

To qualitatively assess the potential for cooling water intake structure impacts on aquatic T&E species, EPA constructed a database that assessed the geographical overlap of cooling water intake structure and habitat used by aquatic T&E species. This database identified the number of T&E species potentially affected by each regulated 316(b) facility, and the number of facilities potentially affecting each T&E species. Additional details are in Chapter 5 of the BA.

Using this database, EPA found 99 Federally-listed aquatic T&E species that overlap with at least one covered cooling water intake structure (an interaction in Exhibit X–8). T&E species included freshwater, marine, and anadromous fish, freshwater mussels, and sea turtles. On average, the habitat of each T&E species overlapped with 22 covered facilities (Exhibit X–8), suggesting that the 316(b) rule may have substantial positive benefits of ensuring the long-term sustainability and recovery of T&E species.

EXHIBIT X–8—NUMBER OF REGULATED 316(B) COOLING WATER INTAKE STRUCTURES IN AQUATIC T&E SPECIES HABITAT ON A PER-SPECIES BASIS

Subset of affected species [a] [b]	Species	Interactions [b]	Facilities per T&E species [c]	
			Avg	Max
All T&E Species	99	2,158	21.8	103
T&E Freshwater Mussels	53	1,176	21.8	103
T&E Anadromous Fish	12	235	19.6	101
T&E Freshwater Fish	21	65	3.1	7
T&E Snails	7	199	28.4	49
Sea Turtles	6	483	80.5	102

[a] Aquatic T&E species includes species listed as threatened or endangered by the U.S. Fish and Wildlife Service (freshwater) or National Oceanic and Atmospheric Administration National Marine Fisheries Service (marine). Only aquatic species overlapping with a minimum of one cooling water intake structure are included.
[b] Each interaction represents an overlap between the range of a T&E species and cooling water intake structure.
[c] Avg = average, Max = maximum.

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b. Quantitative Assessment of Impingement Mortality and Entrainment Impacts on T&E Species

Although difficult to observe and quantify, EPA identified 14 T&E species with confirmed impingement mortality and entrainment based on facility impingement mortality and entrainment studies. EPA notes that some impingement mortality and entrainment studies identifying T&E losses were conducted prior to the listing of the species under the ESA. In addition to documented species-level instances of T&E mortality, EPA identified impingement mortality and entrainment at the level of genera [152] when these genera contain a T&E species whose habitat range overlapped the reporting facility's cooling water intake structure. Although these are not confirmed impingement mortality and entrainment of T&E species, they provide evidence that additional T&E species are likely to be directly affected by impingement mortality and entrainment. EPA found seven genus-level matches, suggesting that the 14 T&E species suffering impingement mortality and entrainment may be inaccurate.

Of the 14 Federally-listed T&E species for which EPA was able to document losses in impingement mortality and entrainment studies, EPA was able to quantify impingement mortality and entrainment for two species (pallid sturgeon and Topeka shiner). The documented impingement mortality and entrainment occurred before these species were Federally-listed. Data were either qualitative or of insufficient quality to quantify local or regional impingement mortality and entrainment for the remaining 12 Federally-listed T&E species. EPA also quantified impingement mortality and entrainment for the American paddlefish (*Polyodon spathula*), listed by several states as threatened or endangered under State law, using facility impingement mortality and entrainment studies. Exhibit X–9 presents EPA's estimates of baseline annual impingement mortality and entrainment, and reductions in impingement mortality and entrainment which EPA estimates will occur under the final rule and other options considered.

EXHIBIT X–9—BASELINE ANNUAL IM&E FOR T&E SPECIES AND REDUCTIONS FOR EXISTING UNITS AT EXISTING FACILITIES (A1ES) [a] [b]

Species	Proposal option 4	Final rule—existing units	Proposal option 2	Baseline
Paddlefish [c]	7,930.1	8,245.4	15,659.7	18,841.4
Pallid Sturgeon	65.4	67.6	78.0	89.5
Topeka Shiner	2,910.9	3,009.8	3,471.9	3,984.9
Total	10,906.4	11,322.8	19,209.5	22,915.7

[a] IM&E = impingement and entrainment; A1E = age-one equivalent.
[b] IM&E Effects by Option: Proposal Option 2 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.
[c] The American paddlefish is not a Federally-listed T&E species but is listed as threatened or endangered on several state lists.
[d] This analysis is based solely on IM controls.

Impingement mortality and entrainment is only one of many factors that adversely affect T&E species. Estimating total population impacts from changes in impingement mortality and entrainment requires estimates of current populations of these fish and estimates of other anthropogenic effects which were not readily available for all T&E species with quantified impingement mortality and entrainment at the time of this analysis. Therefore, EPA was unable to quantify effects on T&E populations from the 316(b) regulation.

c. Valuation Methods of T&E Fish Species

EPA had sufficient data from impingement mortality and entrainment studies to quantify impingement mortality and entrainment estimates for three T&E species, Topeka shiner, pallid sturgeon, and paddlefish (Exhibit X–9). Two of these species (pallid sturgeon and paddlefish) have potential use values. A limited recreational fishery (mostly catch and release) exists for paddlefish in several states; although harvesting pallid sturgeon is illegal, the species is sometimes caught by recreational anglers. EPA estimated recreational use values for pallid sturgeon and paddlefish by applying transfer values from a Random Utility Model analysis it conducted to evaluate recreational fishing benefits of the 316(b) Phase II regulation to quantified impingement mortality and entrainment (for details, see Chapter 5 of the BA).

EPA was unable to generate estimates of nonuse values for T&E fish species because reliable population estimates needed to transfer the values were unavailable. However, EPA emphasizes that nonuse values for T&E fish species are likely to be significantly greater than any use values. Harvest of these species is prohibited, reflecting a societal judgment that protection and preservation of these species is of greater value than harvest.

d. Estimated Monetary Benefits From Reduced Mortality of T&E Fish Species

Exhibit X–10 presents the estimated annualized benefits for a subset of T&E species. For existing units under the final rule, EPA estimates total annualized use benefits for T&E species with quantified impingement mortality and entrainment of $0.4 million using a 3 percent discount rate and $0.3 million using a 7 percent discount rate. For other options considered, annualized benefits range from $0.4 to $0.7 million using a 3 percent discount rate and $0.3 to $0.5 million using a 7 percent discount rate.

[152] Genera is the plural of genus. Genus is the rank superior to species in taxonomic biological classification. For example, the genus of Atlantic salmon (*Salmo falar*) is *Salmo.*

EXHIBIT X–10—ANNUAL USE BENEFITS FROM ELIMINATING OR REDUCING IM&E OF T&E SPECIES AT EXISTING UNITS OF EXISTING FACILITIES FOR THE FINAL RULE AND OTHER OPTIONS CONSIDERED [a b c]

Regulatory option	Increased harvest (number of fish)	3% discount rate (million 2011$)	7% discount rate (million 2011$)
Proposal Option 4	7,995.5	0.4	0.3
Final Rule—Existing Units	8,313.0	0.4	0.3
Proposal Option 2	15,737.7	0.7	0.5
Baseline	18,930.9	1.2	1.3

[a] IM&E = impingement and entrainment; T&E = threatened and endangered. Values are included for pallid sturgeon and paddlefish in the Inland region.
[b] IM&E Effects by Option: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = intake flow commensurate with closed-cycle cooling for facilities that have a DIF of greater than 125 mgd and impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd.
[c] This analysis is based solely on impingement mortality controls.

EPA notes that the benefit values presented in Exhibit X–10 represent only a fraction of values for T&E species potentially affected by the final existing facilities rule. The Agency was able to obtain only use values and for only a small subset of all affected T&E species. Moreover, because of the nature of T&E species, even a small increase in population could yield economic and ecological benefits (e.g., Richardson and Loomis; [153] Bell et al.; [154] Berrens et al.[155])

e. Valuation Methods for T&E Sea Turtles

In addition to estimating values of T&E fish with quantitative estimates of impingement mortality and entrainment, EPA estimated the WTP for sea turtle conservation. In this analysis, EPA applied estimates from a study using a stated preference valuation approach to estimate total economic value of a management program that reduces the risk of extinction of loggerhead sea turtles.[156]

Although impingement mortality and entrainment of turtles is relatively low compared to mortality from shrimp trawling and other fisheries,[157] it is known that reducing turtle mortality during juvenile and subadult life stages can have a substantial positive effect on population growth.[158] The marginal change in extinction probability of sea turtles due to 316(b) regulatory options is likely to be at least 0.01, or a 1 percent decrease in the probability of extinction over 25 years. This assessment is based on reports that impingement mortality and entrainment may result in the loss of more than 100 turtles per year and because turtle population growth rates are known to be sensitive to changes in juvenile and subadult life stages.[159]

f. Benefits From Reduced Mortality of T&E Sea Turtles

The U.S. range of loggerhead sea turtles includes the Gulf of Mexico, South Atlantic, Mid-Atlantic, and North Atlantic 316(b) regions.[160] To calculate national WTP for an increased 25-year survival probability of loggerhead sea turtles, EPA assumed the affected population to include households in States with 316(b) facilities that are in loggerhead sea turtle habitat. EPA determined that 54.8 million households would be willing to pay for improved protection of loggerhead sea turtles. Although incidences of mortality have been reported at facilities in California, Texas, Florida, South Carolina, North Carolina, and New Jersey, EPA does not have sufficient information to quantify total sea turtle losses due to intakes or the reductions in such losses that might occur from the final rule or options considered. But as an illustrative example, assuming that the survival probability of loggerhead sea turtles over 25 years were increased by 1 percent, and applying a mean household value of $0.37 (2011 dollars), the monetized value would be $19.3 million and $18.8 million using discount rates of 3 percent and 7 percent, respectively. EPA is presenting these estimates only to demonstrate the potential range of benefits, and is not including them in national benefits totals for the final rule and options considered. Actual household values and total benefits may be higher or lower than these estimates, with Proposal Option 2 likely to provide substantially greater benefits than the final rule and Proposal Option 4.

Because EPA does not currently have accurate national estimates of impingement mortality and entrainment for turtle species, nor are population models available that estimate the effect of 316(b) regulation on population size and extinction risk, these estimates are presented only as an illustrative example and are not included in national totals.

g. Other Indications of Society's WTP for Protection of T&E Species

Many sources provide information that indicates that society places significant value on protecting T&E species. These include, but are not limited to:

• The Endangered Species Act of 1973, which provides for the conservation of T&E species of fish and wildlife. Federal and State expenditures on T&E species were $593 million during fiscal year 2011 just on protection of those Federally-listed T&E species that have habitat overlapping cooling water intake structures. This accounted for 68 percent of the $869 million spent on fish, marine reptiles, crustaceans, corals, clams, aquatic snails and marine mammals listed under the Endangered Species Act.[161]

[153] Richardson, L., and J. Loomis. 2009. The total economic value of threatened, endangered and rare species: An updated meta-analysis. Ecological Economics, 68(5): 1535–1548.

[154] Bell, K.P., D. Huppert, and R.L. Johnson. 2003. Willingness to pay for local coho salmon enhancement in coastal communities. Marine Resource Economics, 18: 15–31.

[155] Berrens, R.P., P. Ganderton, and C.L. Silva. 1996. Valuing the protection of minimum instream flow in New Mexico. Journal of Agricultural and Resource Economics 21(2): 294–309.

[156] Whitehead, J.C. 1993. Total economic values for coastal and marine wildlife: specification, validity, and valuation issues. Marine Resource Economics, 8(2): 119–132.

[157] Plotkin, P.T., (Ed). 1995. National Marine Fisheries Service and U. S. Fish and Wildlife Service Status Reviews for Sea Turtles Listed under the Endangered Species Act of 1973. National Marine Fisheries Service. Silver Spring, MD.

[158] Crouse, D.T., L.B. Crowder, and H. Caswell. 1987. A stated-based population model for loggerhead sea turtles and implications for conservation. Ecology, 68(5): 1412–1423.

[159] Ibid.

[160] U.S. Fish and Wildlife Service (USFWS) (2010c). ''North Florida Ecological Services Office: Loggerhead Sea Turtle (Caretta).'' Available at *http://www.fws.gov/northflorida/seaturtles/turtle%20factsheets/loggerhead-sea-turtle.htm.*

[161] U.S. Fish and Wildlife Service. 2012. Federal and State Endangered and Threatened Species Expenditures. Fiscal Year 2011.

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• Restrictions on activities in the habitat occupied by T&E species. For example, water diversions on the San Joaquin-Sacramento River delta, in place to protect the Delta Smelt (*Hypomesus transpacificus*), limit the extraction of water for drinking and agriculture.

• The willingness of individuals to volunteer their time to conserve T&E species. For example, dozens of organizations recruit thousands of volunteers every year to participate in sea turtle conservation and research projects. Volunteers are often required to undergo substantial training and commit to long hours.

While costs to replace, protect, or enhance stocks, and costs to users affected by efforts to conserve stocks are not direct measures of economic benefits, they indicate that society is willing to pay significant sums to protect and restore populations of T&E species. Although impingement mortality and entrainment is only one of many stressors on these species, reducing the amount of impingement mortality and entrainment could contribute to the recovery of populations over time, thereby eliminating some costs associated with conserving T&E species.

7. Assessment of Thermal Discharge Impacts

In addition to reducing total impingement mortality and entrainment, closed-cycle cooling reduces thermal pollution. Most retrofit installations of cooling towers at electric generating facilities have been required by NPDES permits to reduce thermal discharges. Since thermal discharges are a product of cooling water intake structures, the impacts of thermal discharges are a relevant benefit to consider when assessing appropriate technologies to reduce the effects of cooling water intakes. The installation of technologies, such as closed-cycle cooling systems, can reduce thermal pollution significantly. Thermal pollution has long been recognized to cause harm to the structure and function of aquatic ecosystems. Concerns about the impacts of thermal discharges are addressed by State water quality standards that, when implemented through NPDES permits, limit the amount of heat that can be discharged to a receiving water and result, in some cases, in technology-based permit conditions. Section 316(a) of the CWA applies to point sources with thermal discharges. It authorizes the NPDES permitting authority to impose alternative effluent limitations for the control of the thermal component of a discharge in lieu of the effluent limitations that would otherwise be required under sections 301 or 306 of the CWA. Before such a ''thermal variance'' can be granted, the permittee must demonstrate that the alternative limit will assure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife in and on the body of water into which the discharge is to be made. 40 CFR 125.73(a).

EPA did not quantify nationally the impacts of thermal discharges. However, numerous studies have shown that thermal discharges may substantially alter the structure of aquatic communities by modifying photosynthetic, metabolic, and growth rates. Thermal discharges also harm aquatic life by reducing levels of dissolved oxygen, altering the location and timing of fish behavior such as spawning, aggregation, and migration, and may cause thermal shock-induced mortality for some species. Adverse temperature effects may also be more pronounced in aquatic ecosystems that are already subject to other environmental stressors such as high levels of biochemical oxygen demand, nutrient and sediment contamination, or pathogens. Within mixing zones, which often extend several miles downstream from outfalls, thermal discharges may impair efforts to restore and protect the waterbody. For example, permit requirements to limit nitrogen discharges in a watershed, and thereby reduce harmful algal blooms, may be counteracted by thermal discharges which promote growth of harmful algae. Thermal discharges may have indirect effects on fish and other vertebrate populations through increasing pathogen growth and infection rates.

Thermal discharges may thus alter the ecological services, and reduce the benefits, of aquatic ecosystems that receive heated effluent. The magnitude of thermal effects on ecosystem services is related to facility-specific factors, including the volume of the waterbody from which cooling water is withdrawn and returned, other heat loads, the rate of water exchange, the presence of nearby refugia, and the assemblage of nearby fish species.

8. Assessment of Social Cost of Carbon

The social cost of carbon reflects the estimated increase in the burden of global warming to society in future years due to higher greenhouse gas (GHG) emissions, measured as CO_2 equivalents, associated with additional energy requirements—energy penalty, auxiliary energy requirements, and compliance technology installation—of regulatory options. EPA estimated positive or negative benefits associated with the social cost of carbon for decreases or increases, respectively for Proposal Option 4 and Final Rule or Proposal Option 2, in energy requirements at regulated facilities under the final rule and other options considered.

EPA's estimates of changes in CO_2 emissions were based on results from the electricity market analysis using IPM.[162] For electric generators, EPA estimated the change in CO_2 resulting from the energy penalty associated with close-cycle recirculating technology, auxiliary energy requirement for operating compliance technology, and technology installation downtime. For manufacturers, EPA estimated the change in carbon emissions resulting from the energy penalty and auxiliary energy requirement. For compliance technology installation downtime at manufacturers, EPA assumed no change in carbon emissions as the short-term replacement of energy by electric power generating facilities that would otherwise be produced at manufacturers could either increase or decrease emissions.

To estimate benefits associated with the reductions in carbon emissions, EPA used social cost of carbon values calculated from the 2013 document titled, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, developed by the U.S. Government Interagency Working Group on Social Cost of Carbon. The Agency used the Working+ Group's annual social cost of carbon values for 2010 through 2050 based on the 3 percent average discount rate, which EPA has concluded is the most appropriate discount rate for intergenerational benefits such as the social cost of carbon. See Chapter 9 of the BA for annual social cost of carbon values based on discount rates of 2.5, 3 (high) and 5 percent. Benefits for each year of the analysis period were calculated by multiplying the change CO_2 emissions by the SCC value for that year. Similar to the treatment of other benefits, EPA discounted all year-specific social cost of carbon values to the beginning of 2013 and calculated an annualized value over 51 years using a 3-percent discount rate. EPA acknowledges that it is mixing estimates of benefits categories analyzed at different discount rates, but finds in this

[162] For this analysis, EPA used the Integrated Planning Model (IPM®), a comprehensive electricity market optimization model that assesses such impacts within the context of regional and national electricity markets.

case that using different discount rates is justified by the intergenerational nature of the social cost of carbon, for purposes of the sensitivity analysis based on a 7 percent discount rate to discount other benefit categories.

Exhibit X–11 presents annualized benefits for existing units for the final rule and options considered. Included in the monetized benefits is EPA's estimate that the final rule will reduce greenhouse gas emissions by 9.3 million tons of CO_2-equivalent emissions over the 40-year compliance period for this analysis. Both the final rule and Proposal Option 4 result in a net reduction in CO_2 emissions for existing units during the analysis period. Proposal Option 2 would result in a net increase in emissions and negative benefits for existing units. Using a 3 percent discount rate, annualized benefits under the final rule for existing units are $12 million. Using a 7 percent discount rate, annualized benefits under final rule for existing units are $13 million.

EXHIBIT X–11—BENEFITS ASSOCIATED WITH SOCIAL COST OF CARBON FOR EXISTING UNITS FOR THE FINAL RULE AND OTHER OPTIONS CONSIDERED

[In millions of 2011 dollars] [a]

Regulatory option [b]	3% Discount rate	7% Discount rate
Proposal Option 4	12.4	13.4
Final Rule—Existing Units	12.4	13.4
Proposal Option 2	−1,643.1	−1,218.2

[a] Benefits are based on the workgroup's average social cost of carbon values using 3 percent rate.

9. Benefits for New Units

In addition to the final rule and other options considered for existing units, EPA analyzed the benefits of the requirements for new units at existing facilities. EPA could not directly apply the benefits methodology used for IM&E (impingement mortality and entrainment) reductions at existing units to new units because it lacks facility-specific information to estimate regional impingement mortality and entrainment reductions for new units. Instead, EPA estimated benefits associated with IM&E reductions for the new unit requirements on the basis of the monetary benefits per million gallons per day from the analysis of existing units. EPA also estimated benefits associated with changes in GHG emissions as the result of the energy penalty associated with operating cooling towers using the social cost of carbon. Exhibit X–12 below presents the estimates of monetized benefits for the new unit requirements. Monetized benefits are −$0.2 million discounted at 3 percent and −$0.1 million discounted at 7 percent.

EXHIBIT X–12—NATIONAL BENEFITS UNDER THE FINAL RULE FOR NEW UNITS AT EXISTING FACILITIES

[In 2011 dollars]

Regulatory option [a]	Monetized benefit categories					
	Recreational fishing	Commercial fishing	Nonuse	T&E species [b]	Social cost of carbon [c]	Total
3% discount rate (millions 2011$)						
Final Rule—New Units	0.0	0.0	0.1	0.0	−0.3	−0.2
7% discount rate (millions 2011$)						
Final Rule—New Units	0.0	0.0	0.0	0.0	*−0.2*	−0.1

[a] IM&E Effects: Final Rule—New Units—entrainment requirements for all stand-alone facilities.
[b] Benefits estimates for T&E species are restricted to recreational fishing benefits from increased catch of T&E species. They do not include benefits for reduced mortality of T&E sea turtles and other nonuse values associated with T&E species.
[c] Benefits are based on the Work Group's average social cost of carbon values using the 3 percent rate.

10. National Monetized Benefits

Quantifying and monetizing reductions in impingement mortality and entrainment attributable to the final rule and other options considered is challenging. National benefit estimates are subject to uncertainties inherent in valuation approaches used to assess the benefits categories (see Chapters 5, 6, 7, 8, 9, and 12 of the BA). While EPA has no data to indicate that the results for each benefit category are atypical or unreasonable, some potentially significant benefit categories have not been fully monetized, and thus the national monetized benefits presented below likely underestimate total benefits.

Exhibit X–13 presents EPA's estimates of the partial monetized benefits from impingement mortality and entrainment reduction and the social cost of carbon for the final rule and other options considered. These monetized values represent use values from increased commercial and recreational catch, benefits transfer of recreational fishing benefits of threatened and endangered species, nonuse values associated with an increase in fish abundance (those fish that are not caught) in the Northeast and Mid-Atlantic benefit regions, and national benefits estimates associated with the social cost of carbon. For the final rule for existing and new units, partial estimated benefits from reducing impingement mortality and entrainment at existing units are $33 million using a 3 percent discount rate and $29 million using a 7 percent discount rate. EPA was not able to fully monetize the benefits for the final rule. Thus, the estimates represent a conservative (i.e., low) estimate of total regulatory benefits of the final rule.

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EXHIBIT X–13—SUMMARY OF NATIONAL BENEFITS FOR ALL REGULATED FACILITIES FOR THE FINAL RULE

Regulatory option [a]	Monetized benefit categories					
	Recreational fishing	Commercial fishing	Nonuse	T&E species [b]	Social cost of carbon [c]	Total
3% discount rate (millions 2011$)						
Final Rule—Existing Units	18.2	0.9	1.0	0.4	12.4	33.0
Final Rule—New Units	0.0	0.0	0.1	0.0	−0.3	−0.2
Final Rule (Existing Units + New Units)	18.3	0.9	1.1	0.4	12.1	32.8
7% discount rate (millions 2011$)						
Final Rule—Existing Units	13.5	0.7	0.8	0.3	13.4	28.7
Final Rule—New Units	0.0	0.0	0.1	0.0	−0.2	−0.1
Final Rule (Existing Units + New Units)	13.5	0.7	0.9	0.3	13.2	28.6

[a] IM&E Effects: Final Rule–Existing Units = impingement mortality standards based on modified traveling screens for all facilities with flow greater than 2 mgd; Final Rule–New Units: Entrainment requirements for all stand-alone facilities where the turbine and condenser are newly built or replaced.
[b] Benefits estimates for T&E species are restricted to benefit transfer of recreational fishing benefits from T&E species. They do not include benefits for reduced mortality of T&E sea turtles and other nonuse values associated with T&E species.
[c] Baseline does not include potential benefits associated with the social cost of carbon.

Exhibit X–14 presents total monetized benefits for the final rule and other options EPA considered for existing units by benefit category using a 3 percent discount rate. Annual monetized benefits are slightly higher for the final rule than Proposal Option 4, and are negative for Proposal Option 2. Including both existing and new units, annual monetized benefits are $32.8 million for the final rule, $30.8 million for Proposal Option 4 and −$1,542.8 million for Proposal Option 2.

EXHIBIT X–14—SUMMARY OF NATIONAL BENEFITS FOR ALL REGULATED FACILITIES FOR THE FINAL RULE AND OTHER OPTIONS EPA CONSIDERED

[3% Discount rate]

Monetized benefit categories	Annual benefits by regulatory option [a] (*millions 2011$*)		
	Proposal option 4	Final rule—existing units	Proposal option 2
Existing Units			
Recreational Fishing	17.1	18.2	43.0
Commercial Fishing	0.9	0.9	3.9
Nonuse	0.3	1.0	51.1
T&E Species [b]	0.4	0.4	0.7
Social Cost of Carbon	12.4	12.4	−1,641.3
Total	31.0	33.0	−1,542.6
Final Rule—New Units			
Total	−0.2	−0.2	−0.2
Existing and New Units			
Total	30.8	32.8	−1,542.8

[a] IM&E Effects: Proposal Option 4 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 50 mgd; Final Rule—Existing Units = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd; Proposal Option 2 = impingement mortality limitations based on modified traveling screens for all facilities with flow greater than 2 mgd and entrainment mortality limitations commensurate with closed-cycle recirculating systems for all facilities with flow greater than 125 DIF; Final Rule—New Units: entrainment requirements for all stand-alone facilities.
[b] Benefits estimates for T&E species are restricted to benefit transfer of recreational fishing benefits from T&E species. They do not include benefits for reduced mortality of T&E sea turtles and other nonuse values associated with T&E species.

EPA recognizes that its estimates of ecological and economic benefits projected to occur under regulation are affected by uncertainty at many levels.

- Not all ecological goods and services affected by cooling water intake structures at regulated 316(b) facilities are modeled or monetized, suggesting that the total benefits of regulation may be underestimated. For example, potential increases in ecosystem stability that might occur as a result of regulation is not explicitly estimated nor monetized.
- When particular ecological goods and services are monetized, data is not always available at the national level. For example, EPA was only able to estimate the nonuse benefits transfer for a species that represents less than one

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percent of adverse environmental impacts.

• For the proposed rule, EPA used a habitat-based method to assess potential WTP for reducing fish mortality at CWIS based on the approximate area of habitat required to produce and support the number of organisms lost to impingement mortality and entrainment.[163] EPA did not consider the habitat-based approach appropriate for primary analysis of benefits for the proposed rule, and did not include it in its analysis for the final rule. However, the results for the proposed rule illustrate that total benefits may be substantially greater than benefits estimated using the methodologies described in Section D.

Because EPA was able to only partially monetize nonuse benefits using the benefits transfer approach, EPA expects that the actual benefits will be greater than those presented here.

XI. Related Acts of Congress, Executive Orders, and Agency Initiatives

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under section 3(f)(1) of E.O. 12866 (58 FR 51735, October 4, 1993), this action is an *economically significant regulatory action* because it is likely to have an annual effect of $100 million or more on the economy. Accordingly, EPA submitted this action to the Office of Management and Budget for review under E.O. 12866 and 13563 (76 FR 3821, January 21, 2011), and any changes made in response to Office of Management and Budget recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the costs and benefits associated with this action; this analysis is discussed in detail in the Chapter 8 of the EA. A copy of the EA is available in the docket for this action, and the analysis is briefly summarized here.

Exhibit XI–1 (drawn from Chapter 8 of the EA) provides the results of the benefit-cost analysis.[164] Placeholders for option-specific non-monetized benefits are represented by B_{P4} for Proposal Option 4, B_{FR} for the final rule and B_{P2} for Proposal Option 2. While preliminary, and not yet reviewed by EPA's Science Advisory Board, the preliminary results of EPA's stated preference survey (see BA, Chapter 11) suggest that B_{P4}, B_{FR}, and B_{P2} have the potential to be significantly different from zero. EPA is therefore using placeholders for additional benefits that are not captured by its analysis of use benefits and the benefits transfer for nonuse benefits. However, EPA did not rely on the results of its stated preference survey in estimating the benefits of today's rule. EPA has concluded that the benefits of the rule justify the costs.

EPA also analyzed the employment effects of the final rule and other options considered in development of this rule. The results of that analysis are summarized in Section IX.E of this preamble and Chapter 9 of the EA.

EXHIBIT XI–1—ANNUALIZED BENEFITS AND COSTS OF THE REGULATORY OPTIONS

[In millions, 2011 dollars] [a]

Option	Total social costs [b]	Benefits [c]
Proposal Option 4	$251.8	$31.0 + B_{P4}
Final Rule	274.9	32.8 + B_{FR}
Proposal Option 2	3,643.2	−1,542.6 + B_{P2}

[a] Social costs and benefits were annualized over 51 years and discounted using 3 percent rate.
[b] Total social costs include compliance costs to facilities and government administrative costs. See EA Chapter 7.
[c] Benefits include social cost of carbon from changes in greenhouse gas emissions due to the final rule.

B. Paperwork Reduction Act

The information collection requirements in this rule will be submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The supporting statement in EPA's information collection request estimates the burden to permitted facilities; burden is defined at 5 CFR 1320.3(b). The 60-day comment period will commence after publication of the draft ICR. The information collection requirements are not enforceable until they are approved by OMB.

Today's rule requires several distinct types of information collection as part of the NPDES permit application. In general, the information will be used to assist EPA in regulating environmental impacts, namely impingement mortality and entrainment, at cooling water intake structures and to identify how a cooling water intake structure at an existing facility or a new unit at an existing facility will meet the impingement mortality and entrainment requirements. Today's rule also requires other reporting and recordkeeping requirements to demonstrate and document compliance with the requirements. Compliance with the applicable information collection requirements established under this final rule is mandatory (see §§ 122.21(r), 125.136, 125.137, 125, and 138).

EPA does not consider the specific data that will be collected under this final rule to be confidential business information. However, if a respondent does consider this information to be confidential, the respondent may request that such information be treated as confidential. All confidential data submitted to EPA will be handled in accordance with 40 CFR 122.7, 40 CFR part 2, and EPA's Security Manual Part III, Chapter 9, dated August 9, 1976.

This final rule modifies regulations at § 122.21 to require each existing facility and new unit at an existing facility to prepare and submit information as part of the facility's NPDES permit application. A detailed list of required data items is provided below.

EPA estimates an average annual burden of 634,596 hours for the final rule's information collection requirements. Of this total, EPA estimates that 1,068 regulated facilities

[163] U.S. EPA. 2011. Environmental and Economic Benefits Analysis for the Proposed Section 316(b) Existing Facilities Rule.

[164] The costs and benefits presented in this section assume that facilities with impoundments will qualify as having closed-cycle recirculating systems in the baseline EPA also conducted the costs and impacts analysis where impoundments were not assumed to meet the definition of closed-cycle recirculating. EPA did not find that this assumption would change EPA's final rule decision; see DCN 12–2501.

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will incur an annual average burden of 588 hours per respondent (for a total of 627,666 burden hours). EPA estimates that Directors in 46 States and one territory with NPDES permitting authority, will incur an annual average burden for the review, oversight, and administration of the rule, of 6,930 hours, or an annual average of 147 hours per permitting authority. Slight differences in calculations are due to rounding.

The corresponding estimate of costs other than labor (labor and non-labor costs are included in the total cost of the final rule discussed in Section IX of this preamble) during the first three years after promulgation of the rule is an annual average of $8.5 million. Non-labor costs include activities such as capital costs for sampling equipment, remote monitoring devices, laboratory services, photocopying, and the purchase of supplies. The burden and costs are for the information collection, reporting, and recordkeeping requirements for the three-year period beginning with the assumed effective date of this rule. Additional information collection requirements will occur after this initial three-year period as (1) existing facilities will continue to gather and submit required permit application materials and (2) new units at existing facilities commence operations and are issued permits.

Information and studies to be submitted under this final rule (as required by §§ 122.21(r) and 125.95) by existing facilities and new units at existing facilities are listed below. For more information, see Section VIII in the preamble.

- Source Water Physical Data (§ 122.21(r)(2))
- Cooling Water Intake Structure Data (§ 122.21(r)(3))
- Source Water Baseline Biological Characterization Data (§ 122.21(r)(4))
- Cooling Water System Data (§ 122.21(r)(5))
- Chosen Method of Compliance With Impingement Mortality Standards (§ 122.21(r)(6))
- Performance Studies (§ 122.21(r)(7))
- Operational Status (§ 122.21(r)(8))
- Entrainment Characterization Study (§ 122.21(r)(9))
- Comprehensive Technical Feasibility and Cost Evaluation Study (§ 122.21(r)(10))
- Benefits Valuation Study (§ 122.21(r)(11))
- Non-Water Quality and Other Environmental Impacts Study (§ 122.21(r)(12))

In addition to the information requirements of the permit application, NPDES permits normally specify monitoring and reporting requirements to be met by the permitted entity. Existing facilities and new units at existing facilities are required to perform monitoring as determined by the requirements in § 125.94 and in accordance with §§ 125.96 and 125.97.

Finally, in accordance with § 125.95(e), facilities are required to maintain records of all submissions that are part of its permit application for a minimum of five years. If the Director approves a request for reduced permit application studies under § 125.95(a) or § 125.98(g), the facility must keep records of all submissions that are part of a previous permit application for an additional five years. Also, facilities must keep records of all submissions that are part of the permit reporting requirements for a period of at least five years from the date of permit issuance, in accordance with § 125.97(d).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA)

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

1. Definition of Small Entities and Estimation of the Number of Small Entities Subject to Today's Final Regulation

For EPA's assessment of the impact of today's final rule on small entities, *small entity* is defined as either (1) a small business as defined by SBA (Small Business Administration) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of fewer than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field. Federal or State entities owning regulated facilities are not small entities.

EPA performed this assessment separately for the two classes of facilities and their owner entities—electric generators and manufacturers—that are subject to today's rule.

a. Electric Generators

EPA followed the SBA criteria for identifying small, non-government entities in the electric power industry, as follows:

- For non-government entities with electric power generation as a primary business, small entities were designated using employment size thresholds specific to each 6-digit NAICS code.
- For government entities other than Federal or State governments, small entities are those with a population of fewer than 50,000.
- For entities with a primary business other than electric power generation, the relevant size criteria are based on revenue or number of employees by NAICS sector (see Exhibit XI–2).

EXHIBIT XI–2—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR ENTITIES THAT OWN ELECTRIC GENERATORS WITH A PRIMARY BUSINESS OTHER THAN ELECTRIC POWER GENERATION

NAICS code	NAICS description	SBA size standard
212111	Bituminous Coal and Lignite Surface Mining	500 employees.
221210	Natural Gas Distribution	500 employees.
331110	Iron and Steel Mills and Ferroalloy Manufacturing	1,000 employees.
331315	Aluminum Sheet, Plate, and Foil Manufacturing	750 employees.
333611	Turbine and Turbine Generator Set Units Manufacturing	1,000 employees.
488320	Marine Cargo Handling	$35.5 million in revenue.
491110	Postal Service	$7 million in revenue.
522110	Commercial Banking	$175 million in assets.
523910	Miscellaneous Intermediation	$7 million in revenue.
524126	Direct Property and Casualty Insurance Carriers	1,500 employees.

EXHIBIT XI–2—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR ENTITIES THAT OWN ELECTRIC GENERATORS WITH A PRIMARY BUSINESS OTHER THAN ELECTRIC POWER GENERATION—Continued

NAICS code	NAICS description	SBA size standard
525910	Open-End Investment Funds	$7 million in revenue.
525990	Other Financial Vehicles	$7 million in revenue.
541990	All Other Professional, Scientific, and Technical Services	$14 million in revenue.
551112	Offices of Other Holding Companies	$7 million in revenue.
562212	Solid Waste Landfill	$35.5 million in revenue.
562219	Other Nonhazardous Waste Treatment and Disposal	$35.5 million in revenue.
562920	Materials Recovery Facilities	$19 million in revenue.
611310	Colleges, Universities, and Professional Schools	$25.5 million in revenue.

EPA conducted this analysis for the same set of parent entities it analyzed in the general entity-level cost-to-revenue analysis discussed in Section IX.D. To determine whether these are small entities on the basis of the size criteria outlined above, EPA compared the relevant measure for the identified parent entities to the appropriate SBA size criterion. EPA conducted this analysis using (1) facility-level weights without using entity-level weights, and (2) entity-level weights without using facility-level weights (for information on these two weighting approaches, see Appendix H of the EA).

EPA estimates that between 31 and 52 small entities own electric generators that are subject to the rule. They represent approximately 25 to 32 percent of entities that own electric generators (see Exhibit XI–3).

EXHIBIT XI–3—NUMBER OF ENTITIES THAT OWN ELECTRIC GENERATORS, BY OWNERSHIP TYPE

Ownership type [a]	Using facility-level weights			Using entity-level weights [b]		
	Total	Small	% Small	Total	Small	% Small
Cooperative	13	11	84.6	21	18	85.7
Federal	1	0	0.0	1	0	0.0
Investor-owned	57	6	10.5	60	7	11.7
Municipality	19	7	36.8	38	19	50.0
Nonutility	26	7	26.9	30	8	26.7
Other Political Subdivision	4	0	0.0	6	0	0.0
State	3	0	0.0	3	0	0.0
All Entity Types	123	31	25.2	159	52	32.7

[a] State and Federal entities are considered large.
[b] In addition to the 52 small parent entities on an unweighted basis, one additional entity is an ''other political subdivision entity'' for a total of 53. This entity owns only implicitly analyzed facilities; consequently, there is no explicitly analyzed entity in the other political subdivision ownership category to represent this implicitly analyzed small parent entity. As the result, weighted entity counts do not include one small other political subdivision entity.

b. Manufacturers

EPA also used the SBA criteria for identifying small, non-government entities in the manufacturing sector. Exhibit XI–4 lists the SBA size threshold guidelines for entities that own manufacturers.

EXHIBIT XI–4—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR ENTITIES THAT OWN MANUFACTURERS

NAICS code	NAICS description	SBA size standard
111930	Sugarcane Farming	$0.75 million in revenue.
113110	Timber Tract Operations	$7 million in revenue.
211111	Crude Petroleum and Natural Gas Extraction	500 employees.
212210	Iron Ore Mining	500 employees.
212391	Potash, Soda, and Borate Mineral Mining	500 employees.
221122	Electric Power Distribution	4,000,000 MWh of electric generation.
311221	Wet Corn Milling	750 employees.
311314	Cane Sugar Manufacturing	750 employees.
311313	Beet Sugar Manufacturing	750 employees.
311942	Spice and Extract Manufacturing	500 employees.
313210	Broadwoven Fabric Mills	1,000 employees.
321113	Sawmills	500 employees.
322121	Paper (except Newsprint) Mills	750 employees.
322122	Newsprint Mills	750 employees.
322130	Paperboard Mills	750 employees.
322211	Corrugated and Solid Fiber Box Manufacturing	500 employees.
322220	Paper Bag and Coated and Treated Paper Manufacturing	500 employees.
322291	Sanitary Paper Product Manufacturing	500 employees.
324110	Petroleum Refineries	1,500 employees.

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EXHIBIT XI–4—NAICS CODES AND SBA ENTITY SIZE STANDARDS FOR ENTITIES THAT OWN MANUFACTURERS—Continued

NAICS code	NAICS description	SBA size standard
324191	Petroleum Lubricating Oil and Grease Manufacturing	500 employees.
325120	Industrial Gas Manufacturing	1,000 employees.
325180	Other Basic Inorganic Chemical Manufacturing	1,000 employees.
325199	All Other Basic Organic Chemical Manufacturing	1,000 employees.
325211	Plastics Material and Resin Manufacturing	750 employees.
325311	Nitrogenous Fertilizer Manufacturing	1,000 employees.
325320	Pesticide and Other Agricultural Chemical Manufacturing	500 employees.
325412	Pharmaceutical Preparation Manufacturing	750 employees.
325510	Paint and Coating Manufacturing	500 employees.
325992	Photographic Film, Paper, Plate and Chemical Manufacturing	500 employees.
325998	All Other Miscellaneous Chemical Product and Preparation Manufacturing	500 employees.
331110	Iron and Steel Mills and Ferroalloy Manufacturing	1,000 employees.
331210	Iron and Steel Pipe and Tube Manufacturing from Purchased Steel	1,000 employees.
331221	Rolled Steel Shape Manufacturing	1,000 employees.
331222	Steel Wire Drawing	1,000 employees.
331313	Alumina Refining and Primary Aluminum Production	1,000 employees.
331315	Aluminum Sheet, Plate and Foil Manufacturing	750 employees.
331410	Nonferrous Metal (except Aluminum) Smelting and Refining	1,000 employees.
332312	Fabricated Structural Metal Manufacturing	500 employees.
337910	Mattress Manufacturing	500 employees.
339999	All Other Miscellaneous Manufacturing	500 employees.
423310	Lumber, Plywood, Millwork, and Wood Panel Merchant Wholesalers	100 employees.
423930	Recyclable Material Merchant Wholesalers	100 employees.
424510	Grain and Field Bean Merchant Wholesalers	100 employees.
424690	Other Chemical and Allied Products Merchant Wholesalers	100 employees.
424710	Petroleum Bulk Stations and Terminals	100 employees.
447190	Other Gasoline Stations	$14 million in revenue.
522220	Sales Financing	$7 million in revenue.
523910	Miscellaneous Intermediation	$7 million in revenue.
523930	Investment Advice	$7 million in revenue.
524126	Direct Property and Casualty Insurance Carriers	1,500 employees.
525990	Other Financial Vehicles	$7 million in revenue.
531110	Lessors of Residential Buildings and Dwellings	$25 million in revenue.
551112	Offices of Other Holding Companies	$7 million in revenue.
561110	Office Administrative Services	$7 million in revenue.

Similar to the analysis conducted for electric generators, EPA conducted this analysis for the same set of parent entities as analyzed in the general, entity-level, cost-to-revenue analysis discussed in Section IX.D. To determine which entities are small, EPA compared the relevant measure for the identified parent entities to the appropriate SBA size criterion. EPA used two sample-weighting schemes in this analysis; these provide a range of counts of small entities that own regulated facilities and the number of regulated facilities that they own that will incur costs under the final rule. EPA does not find either of these sample-weighting schemes to be superior to the other in the quality of the resulting estimates of small entity counts and occurrence of impacts. The different weighting approaches reflect the fact that EPA used sample facilities for the impact analysis and lacks precise information on the profile of ownership of the *total population* of regulated manufacturers facilities—in terms of the number of small entities owning regulated facilities and the number of regulated facilities that any small entity would own. EPA developed the weighting schemes using alternative bounding assumptions about the profile of ownership of regulated facilities by small entities. The weighting schemes provide lower and upper bound estimates of the numbers of small entities, and the numbers of regulated facilities that they own, and accordingly, the number of small entities in each of the cost-to-revenue impact categories (for information on the weighting schemes, see Appendix H of the EA).

From this analysis, EPA estimates that 17 to 52 small entities own regulated facilities in the six Primary Manufacturing Industries, representing approximately 16 percent of all entities that own regulated facilities in these industries (see Exhibit XI–5).The presence of small entities varies by industry sector.

EXHIBIT XI–5—NUMBER OF SMALL ENTITIES THAT OWN REGULATED FACILITIES, BY INDUSTRY

Industry	Lower-bound estimate of number of entities that own regulated facilities			Upper-bound estimate of number of entities that own regulated facilities		
	Total	Small	% Small	Total	Small	% Small
Aluminum	4	2	50.0	11	4	40.6
Chemicals and Allied Products	30	5	16.7	121	21	17.7
Food and Kindred Products	6	0	0.0	20	0	0.0
Paper and Allied Products	37	7	18.9	104	23	21.8
Petroleum Refining	16	2	12.5	25	2	8.4

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EXHIBIT XI–5—NUMBER OF SMALL ENTITIES THAT OWN REGULATED FACILITIES, BY INDUSTRY—Continued

Industry	Lower-bound estimate of number of entities that own regulated facilities			Upper-bound estimate of number of entities that own regulated facilities		
	Total	Small	% Small	Total	Small	% Small
Steel	13	1	7.7	32	2	5.2
Multiple Industries [a]	4	0	0.0	14	0	0.0
Primary Manufacturing Industries [b]—Total	110	17	15.5	327	52	16.0

[a] These are small entities that own regulated facilities from multiple industries.
[b] EPA did not compile comparable information for Other Industries facilities and the entities that own them because it did not have a statistically valid sample of facilities from which to develop such estimates.

c. Total Number of Small Entities That Own Regulated Facilities

EPA estimates that between 48 and 104 small entities own regulated facilities in the electric power industry and six primary manufacturing industries together.

2. Statement of Basis

As described above, EPA began the small entity impact assessment by first estimating the number of small entities in the two industry segments subject to the final rule: Electric generators and manufacturers. EPA next assessed whether these small entities would be expected to incur costs that constitute a significant impact and, finally, assessed whether those entities represent a substantial number of small entities.

EPA summed annualized after-tax compliance costs for regulated facilities that are assumed to be owned by a given small entity and calculated the costs as a percentage of entity revenue (cost-to-revenue test). EPA compared the resulting percentages to impact criteria of 1 and 3 percent of revenue. EPA assumed that small entities estimated to incur costs below 1 percent of revenue will not face significant economic impacts, while small entities with costs of at least 1 percent of revenue have a chance of facing economic impacts. EPA assumed that entities incurring costs of at least 3 percent of revenue have a higher likelihood of economic impacts.

For both electric generators and manufacturers, EPA used sample-weighting approaches that provide a range of estimates of the numbers of small entities and regulated facilities that they own.

Exhibit XI–6 summarizes the Regulatory Flexibility Act analysis results under both weighting approaches for each regulated facilities segment. Overall, the RFA analysis for electric generators found that no small entities would potentially incur a significant impact under the final rule. Specifically, for electric generators, EPA estimates that zero to three small entities will incur costs exceeding 1 percent of revenue, while no small entity will incur costs exceeding 3 percent of revenue. Following EPA's guidance on conducting RFA analyses, the number of small entities above the threshold as a percent of all small entities subject to the rule are zero to 10 percent at the 1 percent of revenue threshold, and zero percent at the 3 percent of revenue threshold.

The findings for manufacturers are comparable. Specifically, EPA estimates that three to four small parent entities will incur costs exceeding 1 percent of revenue, and zero to one small parent entity will incur costs exceeding 3 percent of revenue. The associated percentages of small entities subject to the final rule are 8 percent to 18 percent at the 1 percent threshold, and zero percent to 6 percent at the 3 percent threshold.

Combining the electric generators and manufacturers segments, EPA estimates that three to seven small entities will incur costs exceeding 1 percent of revenue, while zero to one small entity will incur costs exceeding 3 percent of revenue. The corresponding percentages of small entities are 4 to 13 percent at the 1 percent threshold, and zero to 2 percent at the 3 percent threshold.

In summary, under the final rule, EPA estimates that a small number of small parent entities will incur a potentially significant cost impact in the individual regulated industry segments, and overall, for both segments. The maximum number of small entities estimated to incur costs exceeding 1 percent is seven, overall, with three of these small entities in the electric generators segment and four in the manufacturers segment. The maximum number of small entities with costs exceeding 3 percent is one, overall, with no small entities in the electric generators segment and one small entity in the manufacturers segments. In each case, the maximum value reflects the high end of an uncertainty range that is based on different sample weighting approaches. EPA judges that values in the interior of these ranges represent more reasonable estimates of the number of small entities incurring significant impacts. The estimated numbers of entities with significant impacts also represent small percentages of the estimated number of small entities, overall, and in the individual segments. The maximum percentage values at the 1 percent of revenue threshold are 13 percent, overall, 10 percent for electric generators, and 18 percent for manufacturers. At the 3 percent threshold, the maximum percentage values are 2 percent, overall, zero percent for electric generators, and 6 percent for manufacturers. Again, these values reflect the high end of an uncertainty range.

In view of these very modest impacts, EPA judges that the final rule is not consequential in terms of potential impacts for small entities.

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EXHIBIT XI–6—ESTIMATED COST-TO-REVENUE IMPACT FOR SMALL ENTITIES THAT OWN FACILITIES SUBJECT TO THE REGULATION

Regulated Segment	Cost impact category			
	Cost ≥1% of revenue [a]		Cost ≥3% of revenue [a]	
	Number of small entities	% of small regulated entities [b]	Number of small entities [c]	% of small regulated entities [b]
Electric Generators	0 to 3	0% to 10%	0	0%
Manufacturers [d]	3 to 4	8% to 18%	0 to 1	0% to 6%
Electric Generators and Manufacturers [d]	3 to 7	4% to 13%	0 to 1	0% to 2%

[a] For both electric generators and manufacturers, EPA used sample-weighting approaches that provide a range of estimates of the numbers of small entities and regulated facilities they own (see Section VII(D)(a)(iv) for manufactures and see Section VII(D)(b)(1)(b) for electric generator weighting approaches).
[b] Percentage of small entities incurring a cost-to-revenue impact involves range estimates in both the numerator (number of affected entities) and denominator (number of regulated entities).
[c] Entities with cost-to-revenue ratios of at least 3 percent are included in the number of entities with cost-to-revenue such ratios of at least 1 percent.
[d] Entity counts used in these calculations exclude manufacturers in other industries. EPA estimated that one small parent entity that owns regulated facilities in other industries would incur costs exceeding 1 percent of revenue.

3. Certification Statement

Given these findings of very small absolute numbers of small entities estimated to incur significant impacts under the final rule, and low percentages of estimated small entities incurring impacts, I certify that the final rule will not have ''a significant impact on a substantial number of small entities'' (no SISNOSE), overall and by individual industry segment.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995, 2 U.S.C. 1531–1538, requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Today's rule contains a Federal mandate that may result in expenditures by State, local, and Tribal governments, in the aggregate, or the private sector, of $100 million or more (adjusted annually for inflation) in any one year. Accordingly, under Unfunded Mandates Reform Act section 202, EPA has prepared a written statement, which follows below (see Chapter 11 of the EA).

1. Summary of Written Statement

a. Authorizing Legislation

Today's rule is issued under the authority of CWA sections 101, 301, 304, 306, 308, 316, 401, 402, 501, and 510, (33 U.S.C. 1251, 1311, 1314, 1316, 1318, 1326, 1341, 1342, 1361, and 1370). For detailed information on the legal authority of this rule, see Section III of this preamble.

b. Benefit-Cost Analysis

As described above, the costs, benefits and economic impacts reported in this section may be underestimated due to EPA's assumption that facilities with impoundments will qualify as having closed-cycle recirculating systems in the baseline and thus, unless additional controls are required to protect listed species, will incur no technology-related costs. Likewise, for this analysis, because these facilities are assumed not to install compliance technology, EPA also assumed they would achieve no benefits. Accordingly, the benefits reported in this section may be underestimated, based on the assumption of no technology installation for facilities with impoundments.[165] The existing and new unit provisions of today's rule are expected to have total annualized pre-tax (social) costs of $274.9 million. These costs include direct costs incurred by facilities and implementation costs incurred by Federal, State, and local governments. The monetized use and nonuse benefits of the final rule, accounting for the existing and new unit provisions, are estimated to be $32.8 million.[166] EPA notes that these differences are based on a comparison of a partial measure of benefits with a more complete measure of costs; therefore, the results must be interpreted with caution. For a more detailed comparison of the costs and benefits of the final rule, see Chapter 8 of the EA.

[165] This factor in potential underestimation of benefits is separate from other considerations that likely lead to benefits underestimation, as described in this section and in the EA and BA reports.

[166] Both cost and benefit values were annualized over 51 years and discounted at 3 percent. Values include costs and benefits estimated for new units. EPA generated partial estimates of nonuse benefits for resource changes for a species that represents less than one percent of adverse environmental impacts.

EPA notes that States may be able to use existing sources of financial assistance to revise and implement today's rule. CWA section 106 authorizes EPA to award grants to States, Tribes, intertribal consortia, and interstate agencies for administering programs for the prevention, reduction, and elimination of water pollution. These grants may be used for various activities to develop and carry out a water pollution control program, including permitting, monitoring, and enforcement. Thus, State and Tribal NPDES permit programs represent one type of State program that can be funded by CWA section 106 grants.

c. Summary of State, Local, and Tribal Government Input

EPA consulted with State governments and representatives of local governments in developing the rule. The outreach activities are discussed in Section III.A.3 of the preamble to the proposed rule (see 76 FR 22268, April 20, 2011) and Chapter 2 of the TDD. EPA has also conducted additional outreach since the proposed rule, including several conference calls with the Association of Clean Water Administrators (including numerous states) and small business representatives (including some local government officials). EPA also combined its efforts and collected input from State and local government entities during development of the proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, which shares many of the same affected facilities as today's final rule; see 78 FR 34530 (June 7, 2013) for more information. State and local officials attended numerous site visits with

EPA's staff, enabling EPA to gather their input; see DCNs 10–6510, 10–6518, 10–6520, 10–6521, 10–6523 and 10–6524. EPA also responded to requests for information from multiple State and local governments. EPA also attended conferences and participated in workgroups (such as NARUC's 2013 Winter Committee Meetings) where additional information about State and local government interests were presented. Historically, EPA has also conducted a great deal of outreach in developing the previous 316(b) regulations over the past decade; for example, see the Phase I final preamble (66 FR 65331, December 18, 2001), the Phase II final preamble (69 FR 41677, July 9, 2004), and the Phase III final preamble (71 FR 35037, June 16, 2006).

d. Regulatory Option Selected

EPA considered and analyzed several regulatory options to determine the best technology available for minimizing adverse environmental impact. These regulatory options are discussed in Section VI of this preamble. These options included a range of technology-based approaches, from impingement mortality technology at all facilities with a DIF of greater than 50 mgd, to requiring additional impingement mortality controls and intake flow commensurate with closed-cycle cooling for all facilities. As discussed in detail in Section VI, EPA did not select options exclusively because they are the most cost-effective among the options that fulfill the requirements of section 316(b). EPA selected the final rule because it meets the requirement of CWA section 316(b) that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. In addition, EPA has determined that the benefits of the final rule justify the costs, taking into account quantified and qualitative benefits and costs. EPA selected a flexible approach for the final rule from among the options considered; it allows consideration of costs and benefits on a site-specific basis in determining BTA for reducing entrainment and has flexible requirements for reducing impingement mortality.

2. Impact of Compliance Requirements on Small Governments

This rule is not subject to Unfunded Mandates Reform Act section 203 requirements because it contains no regulatory requirements that could significantly or uniquely affect small governments (i.e., governments with a population of fewer than 50,000). For its assessment of the impact of compliance requirements on small governments, EPA compared the estimated total costs and costs per facility that small governments would incur with the costs that large governments would incur. EPA also compared costs for regulated facilities owned by small-government entities with costs of regulated facilities owned by non-government entities. The Agency evaluated costs per facility on the basis of both average and maximum annualized cost. The costs for facilities owned by small government entities are less than those estimated for facilities owned by large government entities, or owned by small or large non-government entities. EPA interprets these findings to indicate that the final rule will not uniquely or disproportionately affect small governments.

Because no manufacturer is government-owned, EPA conducted this analysis for electric generators only.

a. Government-Owned Electric Generators by Ownership and Entity-Size Category

Exhibit XI–7 provides an estimate of the number of non-Federal government entities that own electric generators, by ownership type and size of government entity. As presented in Exhibit XI–7, large government entities own 45 electric generators, and small government entities own 20 electric generators. Of the 65 facilities owned by government entities, 48 are owned by municipalities, six are owned by States and 11 are owned by other political subdivisions. Tribal governments own no regulated facilities.

EXHIBIT XI–7—NUMBER OF GOVERNMENT-OWNED ELECTRIC GENERATORS, BY SIZE OF GOVERNMENT [a]

Entity type	Large	Small	Total
Municipality	29	19	48
State Government	6	0	6
Other Political Subdivision	10	1	11
Tribal Government	0	0	0
Total	45	20	65

[a] Counts of explicitly and implicitly analyzed electric generators; these are not weighted estimates. For details, see EA Appendix H.

b. Compliance Costs for Electric Generators Owned by Small Government Entities

Exhibit XI–8 presents total, average annualized compliance costs, and maximum annualized compliance costs of the final rule for regulated facilities owned by government (State, local, and Tribal governments) and non-government entities by entity-size category. For the existing unit provision of the final rule, EPA estimates that small government entities will incur a total annualized cost of $2.6 million, compared to the total cost of $8.6 million incurred by large government entities and $8.5 million incurred by small private entities. On a per facility basis, EPA estimates that a facility owned by a small government entity will on average incur a cost of $0.2 million with a maximum of $0.5 million. The Agency estimates that for a facility owned by large government entity, the average cost of the existing provision of the final rule will be $0.2 million per facility with a maximum of $1.3 million, while for a facility owned by a small private entity the average cost will be $0.2 million per facility with a maximum of $1.4 million.[167] Again, overall, EPA concludes that the compliance requirements of the existing unit provision of today's rule do not significantly or uniquely affect small governments in comparison to either large governments or small private entities. For details of this analysis, see the EA Chapter 11.

EXHIBIT XI–8—ELECTRIC GENERATORS AND COMPLIANCE COSTS BY OWNERSHIP TYPE AND SIZE

[In millions, 2011 dollars]

Ownership type	Entity size	Number of facilities (weighted) [a]	Total compliance costs	Average cost per facility [d]	Maximum facility cost [e]
Final Rule:					
Government (excluding Federal)	Small	16	$2.6	$0.2	$0.5

[167] Excluding Federal government entities and regulated facilities they own.

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EXHIBIT XI–8—ELECTRIC GENERATORS AND COMPLIANCE COSTS BY OWNERSHIP TYPE AND SIZE—Continued

[In millions, 2011 dollars]

Ownership type	Entity size	Number of facilities (weighted) [a]	Total compliance costs	Average cost per facility [d]	Maximum facility cost [e]
Private [b]	Large	37	8.6	0.2	1.3
	Small	53	8.5	0.2	1.4
	Large	423	184.3	0.4	5.0
All Facilities [c]		544	220	0.4	5.0

[a] Facility counts are weighted estimates and differ from the values reported in Exhibit XI–7, which are un-weighted counts and reflect information for both explicitly and implicitly analyzed electric generators. Sample-weighted values are reported in this table because costs were developed only for the explicitly analyzed electric generators. For details on development of sample weights, see EA Appendix H.
[b] Facility counts and cost estimates reported for the private sector include facilities owned by rural electric cooperatives.
[c] Facility counts and cost estimates reported for All Facilities include facilities owned by the Federal government and costs estimated for these facilities.
[d] EPA calculated average cost per facility using the total number of regulated facilities owned by entities in a given ownership category.
[e] Reflects maximum of un-weighted costs to explicitly analyzed facilities only.

3. Administrative Costs

Section 316(b) requirements are implemented through the NPDES permit program. EPA estimates that 46 States and one territory—the relevant jurisdictions with NPDES permitting authority under CWA section 402(b)—will incur costs to administer the final rule.[168] EPA estimates that States and territories will incur costs for implementing the requirements of today's rule in four activity categories: (1) Start-up activities to learn and understand the requirements of today's regulation and to implement administrative structures and procedures for administering the regulation; (2) initial permit issuance activities; (3) annual activities, including monitoring, reporting and recordkeeping; and (4) non-annually recurring permit-related activities. Exhibit XI–9 presents total annualized costs for each type of administrative activity. EPA estimates that State and local government entities will incur annualized costs of $0.9 million to administer the final rule for electric generators and manufacturers. Monitoring, reporting and recordkeeping costs compose the largest share of administrative costs.

EXHIBIT XI–9—ANNUALIZED GOVERNMENT ADMINISTRATIVE COSTS

[In millions, 2011 dollars]

Activity	Cost		Total
	Electric generators	Manufacturers	
Start-up Activities	NA	NA	[a] $0.0
Initial Permit Issuance Activities	$0.2	$0.2	0.4
Annual Monitoring, Reporting and Recordkeeping Activities	0.2	0.2	0.5
Non-Annually Recurring Permit-Related Activities [b]	[b] 0.0	0.0	0.1
Total	0.5	0.4	0.9

[a] Costs associated with start-up activities are estimated for both electric generators and manufacturers; these costs are less than $20,000.
[b] Costs are less than $50,000.

E. Executive Order 13132: Federalism

Under E.O. 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs on the State and local governments, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the final rule.

The final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in E.O. 13132.This final rule would not alter the basic State-Federal scheme established in the CWA under which EPA authorizes States to carry out the NPDES permitting program. Prior to this rule, authorized States were required to issue NPDES permits including requirements for CWISs on a case-by-case BPJ basis. 40 CFR 125.90(b). EPA expects that today's rule will have little to no effect on the relationship between, or the distribution of power and responsibilities among, the Federal and State governments.

EPA estimates an average annual burden of $0.9 million, for State and local governments to collectively administer the existing unit provision of the final rule.[169] The rule will also impose a compliance cost burden on State and local governments, if those government entities own facilities that are subject to today's rule. EPA has identified 554 regulated facilities that are owned by State or local government entities; the Agency estimates that under the existing unit provision of the final rule these facilities will incur an average annual compliance cost of

[168] Federal government permitting authorities will also incur costs to administer the rule. As stated earlier in this section, consistent with UMRA analysis requirements, EPA did not account for costs to Federal entities in the UMRA analysis.

[169] This estimate does not include costs to administer the new unit provision of the final rule; however, EPA expects these costs to be small.

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approximately $0.2 million per facility.[170] Because this rule does not have federalism implications, the requirements of section 6 of E.O. 13132 do not apply to this rule.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have Tribal implications, as specified in E.O. 13175 (65 FR 67249, November 9, 2000). It would not have substantial direct effects on Tribal governments, on the relationship between the Federal government and the Tribes, or the distribution of power and responsibilities between the Federal government and Tribes as specified in E.O. 13175. The national cooling water intake structure standards would be implemented through permits issued under the NPDES program. No Tribal governments are authorized pursuant to CWA section 402(b) to implement the NPDES program. In addition, EPA's analyses show that Tribal governments own no facilities subject to today's rule; thus, this rule does not affect Tribes in any way now or in the foreseeable future. Thus, E.O. 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to E.O. 13045 because it does not establish an environmental standard intended to mitigate health or safety risks. This rule establishes requirements for cooling water intake structures to protect the environment.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

E.O. 13211 (66 FR 28355, May 22, 2001) requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, for actions identified as *significant energy actions*. On the basis of the Office of Management and Budget's guidance for assessing the potential energy impact of regulations, the Agency anticipates that today's rule may have a significant adverse effect on the supply, distribution, or use of energy, thus requiring EPA to include a Statement of Energy Effects.

The Agency assessed the energy effects of today's rule, specifically, the rule's effect on energy supply, distribution or use in the electric power sector, as required under E.O. 13211. In its energy-effects assessment, EPA relied on Integrated Planning Model (IPM) analyses undertaken by EPA for the final rule. Based on that analysis, described in Section IX(D)(1)(d) of this preamble (Assessment of the Impacts in the Context of Electricity Markets) and in more detail in Chapter 6 of the EA report, EPA finds that the compliance requirements of the final rule may affect the electric power sector in ways that would constitute a significant adverse effect under E.O. 13211, and thus includes a Statement of Energy Effects in the economic analysis.

The Agency's analysis found that the final rule will not reduce electricity production in excess of 1 billion kWh hours per year (or one thousand GWh), will not increase the cost of energy production in excess of 1 percent, will not increase dependence on foreign supply of energy, and will not significantly affect domestic coal production. However, the final rule will result in net retirement of 998 MW of generating capacity, which exceeds 500 MW of installed capacity, the threshold of significant adverse effect identified in the OMB Implementation Guidance for E.O. 13211. EPA notes that, with only one exception, these retirements involve older, less efficient generating units with very low capacity utilization rates. The 998 MW of net retired capacity is replaced by 589 MW of new capacity; therefore, because older and less efficient capacity is replaced by new, more energy-efficient, and less polluting capacity, these retirements mean that 409 MW less capacity is needed to fulfill the same demand.

For more detail on the estimated energy effects of the final rule, see Chapter 12 of the EA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995, Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless doing so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The National Technology Transfer and Advancement Act directs EPA to provide Congress, through the Office of Management and Budget, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This final rulemaking may involve technical standards, for example, in measuring impingement and entrainment. Nothing in this final rule would prevent the use of voluntary consensus standards for such measurements. EPA encourages permitting authorities and regulated entities to use voluntary consensus standards, where they are available.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

E.O. 12898 (59 FR 7629, February 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 today's rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations. Specifically, the final rule increases the level of environmental protection for all affected populations and has no high and adverse human health or environmental effects on any population, including any minority or low-income population. Because EPA expects that this final rule will help to preserve the health of aquatic ecosystems near regulated facilities, EPA expects that all populations, including minority and low-income populations, will benefit from improved environmental conditions.

To meet the objectives of E.O. 12898, EPA assessed whether today's rule could distribute benefits among population subgroups in a way that is significantly less favorable to low-income and minority populations. EPA compared key demographic characteristics of affected substate populations to those demographic characteristics at the State level. If EPA had found that the demographic profile of the substate *benefit population* is composed of a significantly lower share of low-income and/or minority populations than the State's general population, EPA might have assessed the final rule as yielding an unfavorable

[170] Cost values were calculated over the 51-year analysis period used for analysis of social costs, discounted and annualized using a rate of 7 percent (see EA Chapters 7 and 11).

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distribution of benefits, from the perspective of the public policy principles of E.O. 12898. The two sets of demographic variables of interest for this environmental justice analysis are race and ethnicity, and annual household income, which are the variables in the Fish Consumption Pathway Module that best capture the minority and low-income aspects of the affected populations.[171] [172] EPA compared variable averages at the substate and State levels to determine whether the demographic profile of the affected population is consistent with the State profile (for details, see EA Chapter 12).

The comparison of minority populations affected by the regulated facilities to the affected States' overall populations showed no statistically significant difference between these groups. While low-income populations constitute a lower fraction of the benefit population than of the State's overall population in many States, the two groups are not significantly different. EPA thus determined that the final rule does not systematically discriminate against, or exclude or deny participation of, the lower income population group or the minority population group in the benefits of the final rule in a way that would be contrary to the intent of E.O. 12898. Overall, EPA thus concluded that the final rule is consistent with the policy intent of E.O. 12898. Anecdotally, minority (e.g., Native American) and low-income populations might be more likely to include a larger proportion of subsistence fishermen. Because this rule will increase abundance of all fish species in the areas affected by cooling water intakes, it might provide a benefit to subsistence fishermen. To the extent that minority and low-income populations are over-represented in this group, they might especially benefit from this rule.

[171] Annual household income data in the FCP Module are available for the following categories: less than $10,000; $10,000 to $19,999; $20,000 to $24,999; $25,000 to $29,999; $30,000 to $34,999; $35,000 to $39,999; $40,000 to $49,999; $50,000 to $74,999; $75,000 to $99,999; and more than $100,000. For this analysis and previous 316(b) rule analyses, these categories were combined into low- and *not* low-income groups based on the U.S. Department of Health and Human Services' poverty guidelines for a family of four living in the contiguous United States or DC The current (2013) poverty guideline is $23,550, which falls near the upper end of the $20,000 to $24,999 income range (U.S. HHS, 2013). For the current analysis, EPA used $25,000 as the threshold for separating populations into low- and *not* low-income groups.

[172] Race and ethnic categories used in the analysis include white non-Hispanic, white Hispanic, black or African American, Asian or Native Hawaiian or Other Pacific Island, and American Indian and Alaska Native.

K. Executive Order 13158: Marine Protected Areas

E.O. 13158 (65 FR 34909, May 31, 2000) requires EPA to ''expeditiously propose new science-based regulations, as necessary, to ensure appropriate levels of protection for the marine environment.'' EPA may take action to enhance or expand protection of existing marine protected areas and to establish or recommend, as appropriate, new marine protected areas. The purpose of this executive order is to protect significant natural and cultural resources in the marine environment, which means ''those areas of coastal and ocean waters, the Great Lakes and their connecting waters, and submerged lands thereunder, over which the United States exercises jurisdiction, consistent with international law.''

Today's rule recognizes the biological sensitivity of tidal rivers, estuaries, oceans, and the Great Lakes, and their susceptibility to adverse environmental impacts from cooling water intake structures. The rule provides requirements to minimize adverse environmental impacts for cooling water intake structures on these types of waterbodies.

EPA used GIS data of the locations of MPAs (Marine Protected Areas) from the national MPA program (*http://www.mpa.gov/helpful_resources/inventory.html*) to locate regulated facilities in MPAs. Under the final rule, 60 percent of regulated facilities in MPAs obtain reductions in impingement mortality. As noted above, because of EPA's assumption that facilities with impoundments will not need to install compliance technology, this may be an underestimate. EPA cannot estimate reductions in entrainment because they would be based on site-specific determinations of BTA. Therefore, EPA expects that today's rule will advance the objective of the executive order to protect marine areas. For more details on this analysis and analysis results, see BA Chapter 8.

L. 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 October 14, 2014.

List of Subjects

40 CFR Part 122

Environmental protection, Administrative practice and procedure, Confidential business information, Hazardous substances, Reporting and recordkeeping requirements, Water pollution control.

40 CFR Part 125

Environmental protection, Cooling water intake structure, Reporting and recordkeeping requirements, Waste treatment and disposal, Water pollution control.

Dated: May 19, 2014.

Gina McCarthy,

Administrator.

For reasons set out in the preamble, Chapter I of Title 40 of the Code of Federal Regulations is amended as follows:

PART 122—EPA ADMINISTERED PERMIT PROGRAMS: THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

■ 1. The authority citation for part 122 continues to read as follows:

Authority: The Clean Water Act, 33 U.S.C. 1251 *et seq.*

■ 2. The suspension of 40 CFR 122.21(r)(1)(ii) and (r)(5), published on July 9, 2007 (72 FR 37109) is lifted.

■ 3. Section 122.21 is amended as follows:

■ a. Revising paragraph (r)(1).

■ b. Adding paragraphs (r)(4)(ix) through (xii).

■ c. Revising paragraph (r)(5).

■ d. Adding paragraphs (r)(6) through (14).

§ 122.21 Application for a permit (applicable to State programs, see § 123.25).

* * * * *

(r) * * *

(1) * * *

(i) *New facilities with new or modified cooling water intake structures.* New facilities (other than offshore oil and gas extraction facilities) with cooling water intake structures as defined in part 125, subpart I of this chapter, must submit to the Director for review the information required under paragraphs (r)(2) (except (r)(2)(iv)), (3), and (4) (except (r)(4)(ix), (x), (xi), and (xii)) of this section and § 125.86 of this chapter as part of the

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permit application. New offshore oil and gas extraction facilities with cooling water intake structures as defined in part 125, subpart N, of this chapter that are fixed facilities must submit to the Director for review the information required under paragraphs (r)(2) (except (r)(2)(iv)), (3), and (4) (except (r)(4)(ix), (x), (xi), and (xii)) of this section and § 125.136 of this chapter as part of their permit application.

(ii) *Existing facilities.* (A) *All existing facilities.* The owner or operator of an existing facility defined at 40 CFR 125.92(k) must submit to the Director for review the information required under paragraphs (r)(2) and (3) of this section and applicable provisions of paragraphs (r)(4), (5), (6), (7), and (8) of this section.

(B) *Existing facilities greater than 125 mgd AIF.* In addition, the owner or operator of an existing facility that withdraws greater than 125 mgd actual intake flow (AIF), as defined at 40 CFR 125.92 (a), of water for cooling purposes must also submit to the Director for review the information required under paragraphs (r)(9), (10), (11), (12), and (13) of this section. If the owner or operator of an existing facility intends to comply with the BTA (best technology available) standards for entrainment using a closed-cycle recirculating system as defined at 40 CFR 125.92(c), the Director may reduce or waive some or all of the information required under paragraphs (r)(9) through (13) of this section.

(C) *Additional information.* The owner or operator of an existing facility must also submit such additional information as the Director determines is necessary pursuant to 40 CFR 125.98(i).

(D) *New units at existing facilities.* The owner or operator of a new unit at an existing facility, as defined at 40 CFR 125.92(u), must submit or update any information previously provided to the Director by submitting the information required under paragraphs (r)(2), (3), (5), (8), and (14) of this section and applicable provisions of paragraphs (r)(4), (6), and (7) of this section. Requests for and approvals of alternative requirements sought under 40 CFR 125.94(e)(2) or 125.98(b)(7) must be submitted with the permit application.

(E) *New units at existing facilities not previously subject to Part 125.* The owner or operator of a new unit as defined at 40 CFR 125.92(u) at an existing facility not previously subject to part 125 of this chapter that increases the total capacity of the existing facility to more than 2 mgd DIF must submit the information required under paragraphs (r)(2), (3), (5), and (8) of this section and applicable provisions of paragraphs (r)(4), (6), and (7) of this section at the time of the permit application for the new unit. Requests for alternative requirements under 40 CFR 125.94(e)(2) or 125.98(b)(7) must be submitted with the permit application. If the total capacity of the facility will increase to more than 125 mgd AIF, the owner or operator must also submit the information required in paragraphs (r)(9) through (13) of this section. If the owner or operator of an existing facility intends to comply with the BTA (best technology available) standards for entrainment using a closed-cycle recirculating system as defined at 40 CFR 125.92(c), the Director may reduce or waive some or all of the information required under paragraphs (r)(9) through (13) of this section.

(F) If the owner or operator of an existing facility plans to retire the facility before the current permit expires, then the requirements of paragraphs (r)(1)(ii)(A), (B), (C), (D), and (E) of this section do not apply.

(G) If the owner or operator of an existing facility plans to retire the facility after the current permit expires but within one permit cycle, then the Director may waive the requirements of paragraphs (r)(7), (9), (10), (11), (12), and (13) of this section pending a signed certification statement from the owner or operator of the facility specifying the last operating date of the facility.

(H) *All facilities.* The owner or operator of any existing facility or new unit at any existing facility must also submit with its permit application all information received as a result of any communication with a Field Office of the Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service.

* * * * *

(4) * * *

(ix) In the case of the owner or operator of an existing facility or new unit at an existing facility, the *Source Water Baseline Biological Characterization Data* is the information in paragraphs (r)(4)(i) through (xii) of this section.

(x) For the owner or operator of an existing facility, identification of protective measures and stabilization activities that have been implemented, and a description of how these measures and activities affected the baseline water condition in the vicinity of the intake.

(xi) For the owner or operator of an existing facility, a list of fragile species, as defined at 40 CFR 125.92(m), at the facility. The applicant need only identify those species not already identified as fragile at 40 CFR 125.92(m). New units at an existing facility are not required to resubmit this information if the cooling water withdrawals for the operation of the new unit are from an existing intake.

(xii) For the owner or operator of an existing facility that has obtained incidental take exemption or authorization for its cooling water intake structure(s) from the U.S. Fish and Wildlife Service or the National Marine Fisheries Service, any information submitted in order to obtain that exemption or authorization may be used to satisfy the permit application information requirement of paragraph 40 CFR 125.95(f) if included in the application.

(5) *Cooling Water System Data.* The owner or operator of an existing facility must submit the following information for each cooling water intake structure used or intended to be used:

(i) A narrative description of the operation of the cooling water system and its relationship to cooling water intake structures; the proportion of the design intake flow that is used in the system; the number of days of the year the cooling water system is in operation and seasonal changes in the operation of the system, if applicable; the proportion of design intake flow for contact cooling, non-contact cooling, and process uses; a distribution of water reuse to include cooling water reused as process water, process water reused for cooling, and the use of gray water for cooling; a description of reductions in total water withdrawals including cooling water intake flow reductions already achieved through minimized process water withdrawals; a description of any cooling water that is used in a manufacturing process either before or after it is used for cooling, including other recycled process water flows; the proportion of the source waterbody withdrawn (on a monthly basis);

(ii) Design and engineering calculations prepared by a qualified professional and supporting data to support the description required by paragraph (r)(5)(i) of this section; and

(iii) Description of existing impingement and entrainment technologies or operational measures and a summary of their performance, including but not limited to reductions in impingement mortality and entrainment due to intake location and reductions in total water withdrawals and usage.

(6) *Chosen Method(s) of Compliance with Impingement Mortality Standard.* The owner or operator of the facility must identify the chosen compliance

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method for the entire facility; alternatively, the applicant must identify the chosen compliance method for each cooling water intake structure at its facility. The applicant must identify any intake structure for which a BTA determination for Impingement Mortality under 40 CFR 125.94 (c)(11) or (12) is requested. In addition, the owner or operator that chooses to comply via 40 CFR 125.94 (c)(5) or (6) must also submit an *impingement technology performance optimization study* as described below:

(i) If the applicant chooses to comply with 40 CFR 125.94(c)(5), subject to the flexibility for timing provided in 40 CFR 125.95(a)(2), the *impingement technology performance optimization study* must include two years of biological data collection measuring the reduction in impingement mortality achieved by the modified traveling screens as defined at 40 CFR 125.92(s) and demonstrating that the operation has been optimized to minimize impingement mortality. A complete description of the modified traveling screens and associated equipment must be included, including, for example, type of mesh, mesh slot size, pressure sprays and fish return mechanisms. A description of any biological data collection and data collection approach used in measuring impingement mortality must be included:

(A) Collecting data no less frequently than monthly. The Director may establish more frequent data collection;

(B) Biological data collection representative of the impingement and the impingement mortality at the intakes subject to this provision;

(C) A taxonomic identification to the lowest taxon possible of all organisms collected;

(D) The method in which naturally moribund organisms are identified and taken into account;

(E) The method in which mortality due to holding times is taken into account;

(F) If the facility entraps fish or shellfish, a count of entrapment, as defined at 40 CFR 125.92(j), as impingement mortality; and

(G) The percent impingement mortality reflecting optimized operation of the modified traveling screen and all supporting calculations.

(ii) If the applicant chooses to comply with 40 CFR 125.94(c)(6), the *impingement technology performance optimization study* must include biological data measuring the reduction in impingement mortality achieved by operation of the system of technologies, operational measures and best management practices, and demonstrating that operation of the system has been optimized to minimize impingement mortality. This system of technologies, operational measures and best management practices may include flow reductions, seasonal operation, unit closure, credit for intake location, and behavioral deterrent systems. The applicant must document how each system element contributes to the system's performance. The applicant must include a minimum of two years of biological data measuring the reduction in impingement mortality achieved by the system. The applicant must also include a description of any sampling or data collection approach used in measuring the rate of impingement, impingement mortality, or flow reductions.

(A) *Rate of Impingement.* If the demonstration relies in part on a credit for reductions in the rate of impingement in the system, the applicant must provide an estimate of those reductions to be used as credit towards reducing impingement mortality, and any relevant supporting documentation, including previously collected biological data, performance reviews, and previously conducted performance studies not already submitted to the Director. The submission of studies more than 10 years old must include an explanation of why the data are still relevant and representative of conditions at the facility and explain how the data should be interpreted using the definitions of impingement and entrapment at 40 CFR 125.92(n) and (j), respectively. The estimated reductions in rate of impingement must be based on a comparison of the system to a once-through cooling system with a traveling screen whose point of withdrawal from the surface water source is located at the shoreline of the source waterbody. For impoundments that are waters of the United States in whole or in part, the facility's rate of impingement must be measured at a location within the cooling water intake system that the Director deems appropriate. In addition, the applicant must include two years of biological data collection demonstrating the rate of impingement resulting from the system. For this demonstration, the applicant must collect data no less frequently than monthly. The Director may establish more frequent data collection.

(B) *Impingement Mortality.* If the demonstration relies in part on a credit for reductions in impingement mortality already obtained at the facility, the applicant must include two years of biological data collection demonstrating the level of impingement mortality the system is capable of achieving. The applicant must submit any relevant supporting documentation, including previously collected biological data, performance reviews, and previously conducted performance studies not already submitted to the Director. The applicant must provide a description of any sampling or data collection approach used in measuring impingement mortality. In addition, for this demonstration the applicant must:

(*1*) Collect data no less frequently than monthly. The Director may establish more frequent data collection;

(*2*) Conduct biological data collection that is representative of the impingement and the impingement mortality at an intake subject to this provision. In addition, the applicant must describe how the location of the cooling water intake structure in the waterbody and the water column are accounted for in the points of data collection;

(*3*) Include a taxonomic identification to the lowest taxon possible of all organisms to be collected;

(*4*) Describe the method in which naturally moribund organisms are identified and taken into account;

(*5*) Describe the method in which mortality due to holding times is taken into account; and

(*6*) If the facility entraps fish or shellfish, a count of the entrapment, as defined at 40 CFR 125.92(j), as impingement mortality.

(C) *Flow reduction.* If the demonstration relies in part on flow reduction to reduce impingement, the applicant must include two years of intake flows, measured daily, as part of the demonstration, and describe the extent to which flow reductions are seasonal or intermittent. The applicant must document how the flow reduction results in reduced impingement. In addition, the applicant must describe how the reduction in impingement has reduced impingement mortality.

(D) *Total system performance.* The applicant must document the percent impingement mortality reflecting optimized operation of the total system of technologies, operational measures, and best management practices and all supporting calculations. The total system performance is the combination of the impingement mortality performance reflected in paragraphs (r)(6)(ii)(A), (B), and (C) of this section.

(7) *Entrainment Performance Studies.* The owner or operator of an existing facility must submit any previously conducted studies or studies obtained from other facilities addressing technology efficacy, through-facility entrainment survival, and other

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entrainment studies. Any such submittals must include a description of each study, together with underlying data, and a summary of any conclusions or results. Any studies conducted at other locations must include an explanation as to why the data from other locations are relevant and representative of conditions at your facility. In the case of studies more than 10 years old, the applicant must explain why the data are still relevant and representative of conditions at the facility and explain how the data should be interpreted using the definition of entrainment at 40 CFR 125.92(h).

(8) *Operational Status.* The owner or operator of an existing facility must submit a description of the operational status of each generating, production, or process unit that uses cooling water, including but not limited to:

(i) For power production or steam generation, descriptions of individual unit operating status including age of each unit, capacity utilization rate (or equivalent) for the previous 5 years, including any extended or unusual outages that significantly affect current data for flow, impingement, entrainment, or other factors, including identification of any operating unit with a capacity utilization rate of less than 8 percent averaged over a 24-month block contiguous period, and any major upgrades completed within the last 15 years, including but not limited to boiler replacement, condenser replacement, turbine replacement, or changes to fuel type;

(ii) Descriptions of completed, approved, or scheduled uprates and Nuclear Regulatory Commission relicensing status of each unit at nuclear facilities;

(iii) For process units at your facility that use cooling water other than for power production or steam generation, if you intend to use reductions in flow or changes in operations to meet the requirements of 40 CFR 125.94(c), descriptions of individual production processes and product lines, operating status including age of each line, seasonal operation, including any extended or unusual outages that significantly affect current data for flow, impingement, entrainment, or other factors, any major upgrades completed within the last 15 years, and plans or schedules for decommissioning or replacement of process units or production processes and product lines;

(iv) For all manufacturing facilities, descriptions of current and future production schedules; and

(v) Descriptions of plans or schedules for any new units planned within the next 5 years.

(9) *Entrainment Characterization Study.* The owner or operator of an existing facility that withdraws greater than 125 mgd AIF, where the withdrawal of cooling water is measured at a location within the cooling water intake structure that the Director deems appropriate, must develop for submission to the Director an *Entrainment Characterization Study* that includes a minimum of two years of entrainment data collection. The Entrainment Characterization Study must include the following components:

(i) *Entrainment Data Collection Method.* The study should identify and document the data collection period and frequency. The study should identify and document organisms collected to the lowest taxon possible of all life stages of fish and shellfish that are in the vicinity of the cooling water intake structure(s) and are susceptible to entrainment, including any organisms identified by the Director, and any species protected under Federal, State, or Tribal law, including threatened or endangered species with a habitat range that includes waters in the vicinity of the cooling water intake structure. Biological data collection must be representative of the entrainment at the intakes subject to this provision. The owner or operator of the facility must identify and document how the location of the cooling water intake structure in the waterbody and the water column are accounted for by the data collection locations;

(ii) *Biological Entrainment Characterization.* Characterization of all life stages of fish, shellfish, and any species protected under Federal, State, or Tribal law (including threatened or endangered species), including a description of their abundance and their temporal and spatial characteristics in the vicinity of the cooling water intake structure(s), based on sufficient data to characterize annual, seasonal, and diel variations in entrainment, including but not limited to variations related to climate and weather differences, spawning, feeding, and water column migration. This characterization may include historical data that are representative of the current operation of the facility and of biological conditions at the site. Identification of all life stages of fish and shellfish must include identification of any surrogate species used, and identification of data representing both motile and non-motile life-stages of organisms;

(iii) *Analysis and Supporting Documentation.* Documentation of the current entrainment of all life stages of fish, shellfish, and any species protected under Federal, State, or Tribal law (including threatened or endangered species). The documentation may include historical data that are representative of the current operation of the facility and of biological conditions at the site. Entrainment data to support the facility's calculations must be collected during periods of representative operational flows for the cooling water intake structure, and the flows associated with the data collection must be documented. The method used to determine latent mortality along with data for specific organism mortality or survival that is applied to other life-stages or species must be identified. The owner or operator of the facility must identify and document all assumptions and calculations used to determine the total entrainment for that facility together with all methods and quality assurance/quality control procedures for data collection and data analysis. The proposed data collection and data analysis methods must be appropriate for a quantitative survey.

(10) *Comprehensive Technical Feasibility and Cost Evaluation Study.* The owner or operator of an existing facility that withdraws greater than 125 mgd AIF must develop for submission to the Director an engineering study of the technical feasibility and incremental costs of candidate entrainment control technologies. In addition, the study must include the following:

(i) *Technical feasibility.* An evaluation of the technical feasibility of closed-cycle recirculating systems as defined at 40 CFR 125.92(c), fine mesh screens with a mesh size of 2 millimeters or smaller, and water reuse or alternate sources of cooling water. In addition, this study must include:

(A) A description of all technologies and operational measures considered (including alternative designs of closed-cycle recirculating systems such as natural draft cooling towers, mechanical draft cooling towers, hybrid designs, and compact or multi-cell arrangements);

(B) A discussion of land availability, including an evaluation of adjacent land and acres potentially available due to generating unit retirements, production unit retirements, other buildings and equipment retirements, and potential for repurposing of areas devoted to ponds, coal piles, rail yards, transmission yards, and parking lots;

(C) A discussion of available sources of process water, grey water, waste water, reclaimed water, or other waters of appropriate quantity and quality for use as some or all of the cooling water needs of the facility; and

(D) Documentation of factors other than cost that may make a candidate

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technology impractical or infeasible for further evaluation.

(ii) *Other entrainment control technologies.* An evaluation of additional technologies for reducing entrainment may be required by the Director.

(iii) *Cost evaluations.* The study must include engineering cost estimates of all technologies considered in paragraphs (r)(10)(i) and (ii) of this section. Facility costs must also be adjusted to estimate social costs. All costs must be presented as the net present value (NPV) and the corresponding annual value. Costs must be clearly labeled as compliance costs or social costs. The applicant must separately discuss facility level compliance costs and social costs, and provide documentation as follows:

(A) Compliance costs are calculated as after-tax, while social costs are calculated as pre-tax. Compliance costs include the facility's administrative costs, including costs of permit application, while the social cost adjustment includes the Director's administrative costs. Any outages, downtime, or other impacts to facility net revenue, are included in compliance costs, while only that portion of lost net revenue that does not accrue to other producers can be included in social costs. Social costs must also be discounted using social discount rates of 3 percent and 7 percent. Assumptions regarding depreciation schedules, tax rates, interest rates, discount rates and related assumptions must be identified;

(B) Costs and explanation of any additional facility modifications necessary to support construction and operation of technologies considered in paragraphs (r)(10)(i) and (ii) of this section, including but not limited to relocation of existing buildings or equipment, reinforcement or upgrading of existing equipment, and additional construction and operating permits. Assumptions regarding depreciation schedules, interest rates, discount rates, useful life of the technology considered, and any related assumptions must be identified; and

(C) Costs and explanation for addressing any non-water quality environmental and other impacts identified in paragraph (r)(12) of this section. The cost evaluation must include a discussion of all reasonable attempts to mitigate each of these impacts.

(11) *Benefits Valuation Study.* The owner or operator of an existing facility that withdraws greater than 125 mgd AIF must develop for submission to the Director an evaluation of the benefits of the candidate entrainment reduction technologies and operational measures evaluated in paragraph (r)(10) of this section including using the Entrainment Characterization Study completed in paragraph (r)(9) of this section. Each category of benefits must be described narratively, and when possible, benefits should be quantified in physical or biological units and monetized using appropriate economic valuation methods. The benefits valuation study must include, but is not limited to, the following elements:

(i) Incremental changes in the numbers of individual fish and shellfish lost due to impingement mortality and entrainment as defined in 40 CFR 125.92, for all life stages of each exposed species;

(ii) Description of basis for any estimates of changes in the stock sizes or harvest levels of commercial and recreational fish or shellfish species or forage fish species;

(iii) Description of basis for any monetized values assigned to changes in the stock size or harvest levels of commercial and recreational fish or shellfish species, forage fish, and to any other ecosystem or non use benefits;

(iv) A discussion of mitigation efforts completed prior to October 14, 2014 including how long they have been in effect and how effective they have been;

(v) Discussion, with quantification and monetization, where possible, of any other benefits expected to accrue to the environment and local communities, including but not limited to improvements for mammals, birds, and other organisms and aquatic habitats;

(vi) Discussion, with quantification and monetization, where possible, of any benefits expected to result from any reductions in thermal discharges from entrainment technologies.

(12) *Non-water Quality Environmental and Other Impacts Study.* The owner or operator of an existing facility that withdraws greater than 125 mgd AIF must develop for submission to the Director a detailed facility-specific discussion of the changes in non-water quality environmental and other impacts attributed to each technology and operational measure considered in paragraph (r)(10) of this section, including both impacts increased and impacts decreased. The study must include the following:

(i) Estimates of changes to energy consumption, including but not limited to auxiliary power consumption and turbine backpressure energy penalty;

(ii) Estimates of air pollutant emissions and of the human health and environmental impacts associated with such emissions;

(iii) Estimates of changes in noise;

(iv) A discussion of impacts to safety, including documentation of the potential for plumes, icing, and availability of emergency cooling water;

(v) A discussion of facility reliability, including but not limited to facility availability, production of steam, impacts to production based on process unit heating or cooling, and reliability due to cooling water availability;

(vi) Significant changes in consumption of water, including a facility-specific comparison of the evaporative losses of both once-through cooling and closed-cycle recirculating systems, and documentation of impacts attributable to changes in water consumption; and

(vii) A discussion of all reasonable attempts to mitigate each of these factors.

(13) *Peer Review.* If the applicant is required to submit studies under paragraphs (r)(10) through (12) of this section, the applicant must conduct an external peer review of each report to be submitted with the permit application. The applicant must select peer reviewers and notify the Director in advance of the peer review. The Director may disapprove of a peer reviewer or require additional peer reviewers. The Director may confer with EPA, Federal, State and Tribal fish and wildlife management agencies with responsibility for fish and wildlife potentially affected by the cooling water intake structure, independent system operators, and state public utility regulatory agencies, to determine which peer review comments must be addressed. The applicant must provide an explanation for any significant reviewer comments not accepted. Peer reviewers must have appropriate qualifications and their names and credentials must be included in the peer review report.

(14) *New Units.* The applicant must identify the chosen compliance method for the new unit. In addition, the owner or operator that selects the BTA standards for new units at 40 CFR 125.94 (e)(2) as its route to compliance must submit information to demonstrate entrainment reductions equivalent to 90 percent or greater of the reduction that could be achieved through compliance with 40 CFR 125.94(e)(1). The demonstration must include the Entrainment Characterization Study at paragraph (r)(9) of this section. In addition, if data specific to your facility indicates that compliance with the requirements of § 125.94 of this chapter for each new unit would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at

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issue, or would result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement or entrainment, or significant adverse impacts on local energy markets, you must submit all supporting data as part of paragraph (r)(14) of this section. The Director may determine that additional data and information, including but not limited to monitoring, must be included as part of paragraph (r)(14) of this section.

PART 125—CRITERIA AND STANDARDS FOR THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

■ 4. The authority citation for part 125 continues to read as follows:

Authority: The Clean Water Act, 33 U.S.C. 1251 *et seq.,* unless otherwise noted.

Subpart I—[Amended]

■ 5. Section 125.84 is amended by revising paragraphs (c) introductory text and (d)(1) to read as follows:

§ 125.84 As an owner or operator of a new facility, what must I do to comply with this subpart?

* * * * *

(c) *Track I requirements for new facilities that withdraw greater than 2 mgd and less than 10 mgd and that choose not to comply with paragraph (b) of this section.* You must comply with all the following requirements:

* * * * *

(d) * * *

(1) You must demonstrate to the Director that the technologies employed will reduce the level of adverse environmental impact from your cooling water intake structures to a level comparable to that which you would achieve were you to implement the requirements of paragraphs (b)(1) and (2) of this section. This demonstration must include a showing that the impacts to fish and shellfish, including important forage and predator species, within the watershed will be comparable to those which would result if you were to implement the requirements of paragraphs (b)(1) and (2) of this section. The Director will consider information provided by any fishery management agency and may also consider data and information from other sources.

* * * * *

■ 6. Section 125.86 is amended as follows:

■ a. Revise paragraphs (a)(1)(ii), (b)(3) introductory text, and (b)(4)(iii) introductory text.

■ b. Remove and reserve paragraphs (c)(2)(ii), (c)(2)(iv)(C), and (c)(2)(iv)(D)(*2*).

§ 125.86 As an owner or operator of a new facility, what must I collect and submit when I apply for my new or reissued NPDES permit?

(a) * * *

(1) * * *

(ii) The Track I requirements for new facilities that withdraw greater than 2 mgd and less than 10 mgd in § 125.84(c);

* * * * *

(b) * * *

(3) *Source waterbody flow information.* You must submit to the Director the following information to demonstrate that your cooling water intake structure meets the flow requirements in § 125.84(b)(3) or (c)(2).

* * * * *

(4) * * *

(iii) The owner or operator of a new facility required to install design and construction technologies and/or operational measures must develop a plan which explains the technologies and measures selected; this plan shall be based on information collected for the Source Water Biological Baseline Characterization required by 40 CFR 122.21(r)(4). Examples of appropriate technologies include, but are not limited to, wedgewire screens, fine mesh screens, fish handling and return systems, barrier nets, aquatic filter barrier systems, etc. Examples of appropriate operational measures include, but are not limited to, seasonal shutdowns or reductions in flow, and continuous operations of screens, etc. The plan must contain the following information:

* * * * *

■ 7. Section 125.87 is amended by revising paragraphs (a) introductory text and (a)(2) to read as follows:

§ 125.87 As an owner or operator of a new facility, must I perform monitoring?

* * * * *

(a) *Biological monitoring.* You must monitor both impingement and entrainment of the commercial, recreational, and forage base fish and shellfish species identified in either the Source Water Baseline Biological Characterization data required by 40 CFR 122.21(r)(4) or the Comprehensive Demonstration Study required by § 125.86(c)(2), depending on whether you chose to comply with Track I or Track II. The monitoring methods used must be consistent with those used for the Source Water Baseline Biological Characterization data required in 40 CFR 122.21(r)(4) or the Comprehensive Demonstration Study required by § 125.86(c)(2). You must follow the monitoring frequencies identified below for at least two (2) years after the initial permit issuance. After that time, the Director may approve a request for less frequent sampling in the remaining years of the permit term and when the permit is reissued, if the Director determines the supporting data show that less frequent monitoring would still allow for the detection of any seasonal and daily variations in the species and numbers of individuals that are impinged or entrained.

* * * * *

(2) *Entrainment sampling.* You must collect samples at least biweekly to monitor entrainment rates (simple enumeration) for each species over a 24-hour period during the primary period of reproduction, larval recruitment, and peak abundance identified during the Source Water Baseline Biological Characterization required by 40 CFR 122.21(r)(4) or the Comprehensive Demonstration Study required in § 125.86(c)(2). You must collect samples only when the cooling water intake structure is in operation.

* * * * *

■ 8. Section 125.89 is amended by revising paragraphs (a) introductory text and (b)(1)(i) and (ii) to read as follows:

§ 125.89 As the Director, what must I do to comply with the requirements of this subpart?

(a) *Permit application.* As the Director, you must review materials submitted by the applicant under 40 CFR 122.21(r)(4) and § 125.86 at the time of the initial permit application and before each permit renewal or reissuance.

* * * * *

(b) * * *

(1) * * *

(i) If an owner or operator of a facility chooses Track I, you must review the Design and Construction Technology Plan required in § 125.86(b)(4) to evaluate the suitability and feasibility of the technology proposed to minimize impingement mortality and entrainment of all life stages of fish and shellfish. In the first permit issued, you must put a condition requiring the facility to reduce impingement mortality and entrainment commensurate with the implementation of the technologies in the permit. Under subsequent permits, the Director must review the performance of the technologies implemented and require additional or different design and construction technologies, if needed to minimize impingement mortality and entrainment

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of all life stages of fish and shellfish. In addition, you must consider whether more stringent conditions are reasonably necessary in accordance with § 125.84(e).

(ii) If an owner or operator of a facility chooses Track II, you must review the information submitted with the Comprehensive Demonstration Study required in § 125.86(c)(2) and evaluate the suitability of the proposed design and construction technologies and operational measures to determine whether they will reduce both impingement mortality and entrainment of all life stages of fish and shellfish to 90 percent or greater of the reduction that could be achieved through Track I. In addition, you must review the Verification Monitoring Plan in § 125.86(c)(2)(iv)(D) and require that the proposed monitoring begin at the start of operations of the cooling water intake structure and continue for a sufficient period of time to demonstrate that the technologies and operational measures meet the requirements in § 125.84(d)(1). Under subsequent permits, the Director must review the performance of the additional and/or different technologies or measures used and determine that they reduce the level of adverse environmental impact from the cooling water intake structures to a comparable level that the facility would achieve were it to implement the requirements of § 125.84(b)(1) and (2).

* * * * *

■ 9. The suspension of 40 CFR 125.90(a), (c), and (d), and 125.91 through 125.99, published on July 9, 2007 (72 FR 37109) is lifted.

■ 10. Subpart J to part 125 is revised to read as follows:

Subpart J—Requirements Applicable to Cooling Water Intake Structures for Existing Facilities Under Section 316(b) of the Clean Water Act

Sec.

125.90 Purpose of this subpart.
125.91 Applicability.
125.92 Special definitions.
125.93 [Reserved]
125.94 As an owner or operator of an existing facility, what must I do to comply with this subpart?
125.95 Permit application and supporting information requirements.
125.96 Monitoring requirements.
125.97 Other permit reporting and recordkeeping requirements.
125.98 Director requirements.
125.99 [Reserved]

Subpart J—Requirements Applicable to Cooling Water Intake Structures for Existing Facilities Under Section 316(b) of the Clean Water Act

§ 125.90 Purpose of this subpart.

(a) This subpart establishes the section 316(b) requirements that apply to cooling water intake structures at existing facilities that are subject to this subpart. These requirements include a number of components. These include standards for minimizing adverse environmental impact associated with the use of cooling water intake structures and required procedures (e.g., permit application requirements, information submission requirements) for establishing the appropriate technology requirements at certain specified facilities as well as monitoring, reporting, and recordkeeping requirements to demonstrate compliance. In combination, these components represent the best technology available for minimizing adverse environmental impact associated with the use of cooling water intake structures at existing facilities. These requirements are to be established and implemented in National Pollutant Discharge Elimination System (NPDES) permits issued under the Clean Water Act (CWA).

(b) Cooling water intake structures not subject to requirements under §§ 125.94 through 125.99 or subparts I or N of this part must meet requirements under section 316(b) of the CWA established by the Director on a case-by-case, best professional judgment (BPJ) basis.

(c) Nothing in this subpart shall be construed to preclude or deny the right under section 510 of the CWA of any State or political subdivision of a State or any interstate agency to adopt or enforce any requirement with respect to control or abatement of pollution that is more stringent than required by Federal law.

Note to § 125.90. This regulation does not authorize take, as defined by the Endangered Species Act, 16 U.S.C. 1532(19). The U.S. Fish and Wildlife Service and National Marine Fisheries Service have determined that any impingement (including entrapment) or entrainment of Federally-listed species constitutes take. Such take may be authorized pursuant to the conditions of a permit issued under 16 U.S.C. 1539(a) or where consistent with an Incidental Take Statement contained in a Biological Opinion pursuant to 16 U.S.C. 1536(o).

§ 125.91 Applicability.

(a) The owner or operator of an existing facility, as defined in § 125.92(k), is subject to the requirements at §§ 125.94 through 125.99 if:

(1) The facility is a point source;

(2) The facility uses or proposes to use one or more cooling water intake structures with a cumulative design intake flow (DIF) of greater than 2 million gallons per day (mgd) to withdraw water from waters of the United States; and

(3) Twenty-five percent or more of the water the facility withdraws on an actual intake flow basis is used exclusively for cooling purposes.

(b) Use of a cooling water intake structure includes obtaining cooling water by any sort of contract or arrangement with one or more independent suppliers of cooling water if the independent supplier withdraws water from waters of the United States but is not itself a new or existing facility as defined in subparts I or J of this part, except as provided in paragraphs (c) and (d) of this section. An owner or operator of an existing facility may not circumvent these requirements by creating arrangements to receive cooling water from an entity that is not itself a facility subject to subparts I or J of this part.

(c) Obtaining cooling water from a public water system, using reclaimed water from wastewater treatment facilities or desalination plants, or recycling treated process wastewater effluent as cooling water does not constitute use of a cooling water intake structure for purposes of this subpart.

(d) This subpart does not apply to offshore seafood processing facilities, offshore liquefied natural gas terminals, and offshore oil and gas extraction facilities that are existing facilities as defined in § 125.92(k). The owners and operators of such facilities must meet requirements established by the Director on a case-by-case, best professional judgment (BPJ) basis.

§ 125.92 Special definitions.

In addition to the definitions provided in 40 CFR 122.2, the following special definitions apply to this subpart:

(a) *Actual Intake Flow* (AIF) means the average volume of water withdrawn on an annual basis by the cooling water intake structures over the past three years. After October 14, 2019, *Actual Intake Flow* means the average volume of water withdrawn on an annual basis by the cooling water intake structures over the previous five years. Actual intake flow is measured at a location within the *cooling water intake*

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structure that the Director deems appropriate. The calculation of actual intake flow includes days of zero flow. AIF does not include flows associated with emergency and fire suppression capacity.

(b) *All life stages of fish and shellfish* means eggs, larvae, juveniles, and adults. It does not include members of the infraclass Cirripedia in the subphylum Crustacea (barnacles), green mussels (*Perna viridis*), or zebra mussels (*Dreissena polymorpha*). The Director may determine that all life stages of fish and shellfish does not include other specified nuisance species.

(c) *Closed-cycle recirculating system* means a system designed and properly operated using minimized make-up and blowdown flows withdrawn from a water of the United States to support contact or non-contact cooling uses within a facility, or a system designed to include certain impoundments. A closed-cycle recirculating system passes cooling water through the condenser and other components of the cooling system and reuses the water for cooling multiple times.

(1) *Closed-cycle recirculating system* includes a facility with wet, dry, or hybrid cooling towers, a system of impoundments that are not waters of the United States, or any combination thereof. A properly operated and maintained closed-cycle recirculating system withdraws new source water (make-up water) only to replenish losses that have occurred due to blowdown, drift, and evaporation. If waters of the United States are withdrawn for purposes of replenishing losses to a closed-cycle recirculating system other than those due to blowdown, drift, and evaporation from the cooling system, the Director may determine a cooling system is a closed-cycle recirculating system if the facility demonstrates to the satisfaction of the Director that make-up water withdrawals attributed specifically to the cooling portion of the cooling system have been minimized.

(2) *Closed-cycle recirculating system* also includes a system with impoundments of waters of the U.S. where the impoundment was constructed prior to October 14, 2014 and created for the purpose of serving as part of the cooling water system as documented in the project purpose statement for any required Clean Water Act section 404 permit obtained to construct the impoundment. In the case of an impoundment whose construction pre-dated the CWA requirement to obtain a section 404 permit, documentation of the project's purpose must be demonstrated to the satisfaction of the Director. This documentation could be some other license or permit obtained to lawfully construct the impoundment for the purposes of a cooling water system, or other such evidence as the Director finds necessary. For impoundments constructed in uplands or not in waters of the United States, no documentation of a section 404 or other permit is required. If waters of the United States are withdrawn for purposes of replenishing losses to a closed-cycle recirculating system other than those due to blowdown, drift, and evaporation from the cooling system, the Director may determine a cooling system is a closed-cycle recirculating system if the facility demonstrates to the satisfaction of the Director that make-up water withdrawals attributed specifically to the cooling portion of the cooling system have been minimized.

(d) *Contact cooling water* means water used for cooling which comes into direct contact with any raw material, product, or byproduct. Examples of contact cooling water may include but are not limited to quench water at facilities, cooling water in a cracking unit, and cooling water directly added to food and agricultural products processing.

(e) *Cooling water* means water used for contact or non-contact cooling, including water used for equipment cooling, evaporative cooling tower makeup, and dilution of effluent heat content. The intended use of the cooling water is to absorb waste heat rejected from the process or processes used, or from auxiliary operations on the facility's premises. Cooling water obtained from a public water system, reclaimed water from wastewater treatment facilities or desalination plants, treated effluent from a manufacturing facility, or cooling water that is used in a manufacturing process either before or after it is used for cooling as process water, is not considered cooling water for the purposes of calculating the percentage of a facility's intake flow that is used for cooling purposes in § 125.91(a)(3).

(f) *Cooling water intake structure* means the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the United States. The cooling water intake structure extends from the point at which water is first withdrawn from waters of the United States up to, and including the intake pumps.

(g) *Design intake flow* (DIF) means the value assigned during the cooling water intake structure design to the maximum instantaneous rate of flow of water the cooling water intake system is capable of withdrawing from a source waterbody. The facility's DIF may be adjusted to reflect permanent changes to the maximum capabilities of the cooling water intake system to withdraw cooling water, including pumps permanently removed from service, flow limit devices, and physical limitations of the piping. DIF does not include values associated with emergency and fire suppression capacity or redundant pumps (i.e., back-up pumps).

(h) *Entrainment* means any life stages of fish and shellfish in the intake water flow entering and passing through a cooling water intake structure and into a cooling water system, including the condenser or heat exchanger. Entrainable organisms include any organisms potentially subject to *entrainment.* For purposes of this subpart, *entrainment* excludes those organisms that are collected or retained by a sieve with maximum opening dimension of 0.56 inches. Examples of sieves meeting this definition include but are not limited to a ⅜ inch square mesh, or a ½ by ¼ inch mesh. A facility must use the same mesh size when counting entrainment as is used when counting impingement.

(i) *Entrainment mortality* means death as a result of entrainment through the cooling water intake structure, or death as a result of exclusion from the cooling water intake structure by fine mesh screens or other protective devices intended to prevent the passage of entrainable organisms through the cooling water intake structure.

(j) *Entrapment* means the condition where impingeable fish and shellfish lack the means to escape the cooling water intake. *Entrapment* includes but is not limited to: Organisms caught in the bucket of a traveling screen and unable to reach a fish return; organisms caught in the forebay of a cooling water intake system without any means of being returned to the source waterbody without experiencing mortality; or cooling water intake systems where the velocities in the intake pipes or in any channels leading to the forebay prevent organisms from being able to return to the source waterbody through the intake pipe or channel.

(k) *Existing facility* means any facility that commenced construction as described in 40 CFR 122.29(b)(4) on or before January 17, 2002 (or July 17, 2006 for an offshore oil and gas extraction facility) and any modification of, or any addition of a unit at such a facility. A facility built adjacent to another facility would be a new facility while the original facility would remain as an exiting facility for purposes of this subpart. A facility cannot both be an existing facility and a new facility as defined at § 125.83.

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(l) *Flow reduction* means any modification to a cooling water intake structure or its operation that serves to reduce the volume of cooling water withdrawn. Examples include, but are not limited to, variable speed pumps, seasonal flow reductions, wet cooling towers, dry cooling towers, hybrid cooling towers, unit closures, or substitution for withdrawals by reuse of effluent from a nearby facility.

(m) *Fragile species* means those species of fish and shellfish that are least likely to survive any form of impingement. For purposes of this subpart, *fragile species* are defined as those with an impingement survival rate of less than 30 percent, including but not limited to alewife, American shad, Atlantic herring, Atlantic long-finned squid, Atlantic menhaden, bay anchovy, blueback herring, bluefish, butterfish, gizzard shad, grey snapper, hickory shad, menhaden, rainbow smelt, round herring, and silver anchovy.

(n) *Impingement* means the entrapment of any life stages of fish and shellfish on the outer part of an intake structure or against a screening device during periods of intake water withdrawal. For purposes of this subpart, *impingement* includes those organisms collected or retained on a sieve with maximum distance in the opening of 0.56 inches, and excludes those organisms that pass through the sieve. Examples of sieves meeting this definition include but are not limited to a ⅜ inch square mesh, or a ½ by ¼ inch mesh. This definition is intended to prevent the conversion of entrainable organisms to counts of impingement or impingement mortality. The owner or operator of a facility must use a sieve with the same mesh size when counting entrainment as is used when counting impingement.

(o) *Impingement mortality* (IM) means death as a result of impingement. Impingement mortality also includes organisms removed from their natural ecosystem and lacking the ability to escape the cooling water intake system, and thus subject to inevitable mortality.

(p) *Independent supplier* means an entity, other than the regulated facility, that owns and operates its own cooling water intake structure and directly withdraws water from waters of the United States. The supplier provides the cooling water to other facilities for their use, but may itself also use a portion of the water. An entity that provides potable water to residential populations (e.g., public water system) is not a supplier for purposes of this subpart.

(q) *Latent mortality* means the delayed mortality of organisms that were initially alive upon being impinged or entrained but that do not survive the delayed effects of impingement and entrainment during an extended holding period. Delayed effects of impingement and entrainment include but are not limited to temperature change, physical stresses, and chemical stresses.

(r) *Minimize* means to reduce to the smallest amount, extent, or degree reasonably possible.

(s) *Modified traveling screen* means a traveling water screen that incorporates measures protective of fish and shellfish, including but not limited to: Screens with collection buckets or equivalent mechanisms designed to minimize turbulence to aquatic life; addition of a guard rail or barrier to prevent loss of fish from the collection system; replacement of screen panel materials with smooth woven mesh, drilled mesh, molded mesh, or similar materials that protect fish from descaling and other abrasive injury; continuous or near-continuous rotation of screens and operation of fish collection equipment to ensure any impinged organisms are recovered as soon as practical; a low pressure wash or gentle vacuum to remove fish prior to any high pressure spray to remove debris from the screens; and a fish handling and return system with sufficient water flow to return the fish directly to the source water in a manner that does not promote predation or re-impingement of the fish, or require a large vertical drop. The Director may approve of fish being returned to water sources other than the original source water, taking into account any recommendations from the Services with respect to endangered or threatened species. Examples of *modified traveling screens* include, but are not limited to: Modified Ristroph screens with a fish handling and return system, dual flow screens with smooth mesh, and rotary screens with fish returns or vacuum returns.

(t) *Moribund* means dying; close to death.

(u) *New unit* means a new ''stand-alone'' unit at an existing facility where construction of the new unit begins after October 14, 2014 and that does not otherwise meet the definition of a new facility at § 125.83 or is not otherwise already subject to subpart I of this part. A stand-alone unit is a separate unit that is added to a facility for either the same general industrial operation or another purpose. A new unit may have its own dedicated cooling water intake structure, or the new unit may use an existing or modified cooling water intake structure.

(v) *Offshore velocity cap* means a velocity cap located a minimum of 800 feet from the shoreline. A velocity cap is an open intake designed to change the direction of water withdrawal from vertical to horizontal, thereby creating horizontal velocity patterns that result in avoidance of the intake by fish and other aquatic organisms. For purposes of this subpart, the velocity cap must use bar screens or otherwise exclude marine mammals, sea turtles, and other large aquatic organisms.

(w) *Operational measure* means a modification to any operation that serves to minimize impact to all life stages of fish and shellfish from the cooling water intake structure. Examples of *operational measures* include, but are not limited to, more frequent rotation of traveling screens, use of a low pressure wash to remove fish prior to any high pressure spray to remove debris, maintaining adequate volume of water in a fish return, and debris minimization measures such as air sparging of intake screens and/or other measures taken to maintain the design intake velocity.

(x) *Social benefits* means the increase in social welfare that results from taking an action. Social benefits include private benefits and those benefits not taken into consideration by private decision makers in the actions they choose to take, including effects occurring in the future. Benefits valuation involves measuring the physical and biological effects on the environment from the actions taken. Benefits are generally treated one or more of three ways: A narrative containing a qualitative discussion of environmental effects, a quantified analysis expressed in physical or biological units, and a monetized benefits analysis in which dollar values are applied to quantified physical or biological units. The dollar values in a social benefits analysis are based on the principle of willingness-to-pay (WTP), which captures monetary benefits by measuring what individuals are willing to forgo in order to enjoy a particular benefit. Willingness-to-pay for nonuse values can be measured using benefits transfer or a stated preference survey.

(y) *Social costs* means costs estimated from the viewpoint of society, rather than individual stakeholders. Social cost represents the total burden imposed on the economy; it is the sum of all opportunity costs incurred associated with taking actions. These opportunity costs consist of the value lost to society of all the goods and services that will not be produced and consumed as a facility complies with permit requirements, and society reallocates

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resources away from other production activities and towards minimizing adverse environmental impacts.

§ 125.93 [Reserved]

§ 125.94 As an owner or operator of an existing facility, what must I do to comply with this subpart?

(a) *Applicable Best Technology Available for Minimizing Adverse Environmental Impact (BTA) standards.* (1) On or after October 14, 2014, the owner or operator of an existing facility with a cumulative design intake flow (DIF) greater than 2 mgd is subject to the BTA (best technology available) standards for impingement mortality under paragraph (c) of this section, and entrainment under paragraph (d) of this section including any measures to protect Federally-listed threatened and endangered species and designated critical habitat established under paragraph (g) of this section.

(2) Prior to *October 14, 2014,* the owner or operator of an existing facility with a cumulative design intake flow (DIF) greater than 2 mgd is subject to site-specific impingement mortality and entrainment requirements as determined by the Director on a case-by-case Best Professional Judgment basis. The Director's BTA determination may be based on consideration of some or all of the factors at § 125.98(f)(2) and (3) and the requirements of § 125.94(c). If the Director requires additional information to make the decision on what BTA requirements to include in the applicant's permit for impingement mortality and entrainment, the Director should consider whether to require any of the information at 40 CFR 122.21(r).

(3) The owner or operator of a new unit is subject to the impingement mortality and entrainment standards under paragraph (e) of this section for all cooling water intake flows used by the new unit. The remainder of the existing facility is subject to the impingement mortality standard under paragraph (c) of this section, and the entrainment standard under paragraph (d) of this section. The entire existing facility including any new units is subject to any measures to protect Federally-listed threatened and endangered species and designated critical habitat established under paragraph (g) of this section.

(b) *Compliance with BTA standards.* (1) *Aligning compliance deadlines for impingement mortality and entrainment requirements.* After issuance of a final permit that establishes the entrainment requirements under § 125.94(d), the owner or operator of an existing facility must comply with the impingement mortality standard in § 125.94(c) as soon as practicable. The Director may establish interim compliance milestones in the permit.

(2) After issuance of a final permit establishing the entrainment requirements under § 125.94(d), the owner or operator of an existing facility must comply with the entrainment standard as soon as practicable, based on a schedule of requirements established by the Director. The Director may establish interim compliance milestones in the permit.

(3) The owner or operator of a new unit at an existing facility must comply with the BTA standards at § 125.94(e) with respect to the new unit upon commencement of the new unit's operation.

(c) *BTA Standards for Impingement Mortality.* The owner or operator of an existing facility must comply with one of the alternatives in paragraphs (c)(1) through (7) of this section, except as provided in paragraphs (c)(11) or (12) of this section, when approved by the Director. In addition, a facility may also be subject to the requirements of paragraphs (c)(8), (c)(9), or (g) of this section if the Director requires such additional measures.

(1) *Closed-cycle recirculating system.* A facility must operate a closed-cycle recirculating system as defined at § 125.92(c). In addition, you must monitor the actual intake flows at a minimum frequency of daily. The monitoring must be representative of normal operating conditions, and must include measuring cooling water withdrawals, make-up water, and blow down volume. In lieu of daily intake flow monitoring, you may monitor your cycles of concentration at a minimum frequency of daily; or

(2) *0.5 Feet Per Second Through-Screen Design Velocity.* A facility must operate a cooling water intake structure that has a maximum design through-screen intake velocity of 0.5 feet per second. The owner or operator of the facility must submit information to the Director that demonstrates that the maximum design intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 feet per second. The maximum velocity must be achieved under all conditions, including during minimum ambient source water surface elevations (based on BPJ using hydrological data) and during periods of maximum head loss across the screens or other devices during normal operation of the intake structure; or

(3) *0.5 Feet Per Second Through-Screen Actual Velocity.* A facility must operate a cooling water intake structure that has a maximum through-screen intake velocity of 0.5 feet per second. The owner or operator of the facility must submit information to the Director that demonstrates that the maximum intake velocity as water passes through the structural components of a screen measured perpendicular to the screen mesh does not exceed 0.5 feet per second. The maximum velocity must be achieved under all conditions, including during minimum ambient source water surface elevations (based on best professional judgment using hydrological data) and during periods of maximum head loss across the screens or other devices during normal operation of the intake structure. The Director may authorize the owner or operator of the facility to exceed the 0.5 fps velocity at an intake for brief periods for the purpose of maintaining the cooling water intake system, such as backwashing the screen face. If the intake does not have a screen, the maximum intake velocity perpendicular to the opening of the intake must not exceed 0.5 feet per second during minimum ambient source water surface elevations. In addition, you must monitor the velocity at the screen at a minimum frequency of daily. In lieu of velocity monitoring at the screen face, you may calculate the through-screen velocity using water flow, water depth, and the screen open areas; or

(4) *Existing offshore velocity cap.* A facility must operate an existing offshore velocity cap as defined at § 125.92(v) that was installed on or before October 14, 2014. Offshore velocity caps installed after October 14, 2014 must make either a demonstration under paragraph (c)(6) of this section or meet the performance standard under paragraph (c)(7) of this section. In addition, you must monitor your intake flow at a minimum frequency of daily; or

(5) *Modified traveling screens.* A facility must operate a modified traveling screen that the Director determines meets the definition at § 125.92(s) and that, after review of the information required in the *impingement technology performance optimization study* at 40 CFR 122.21(r)(6)(i), the Director determines is the best technology available for impingement reduction at the site. As the basis for the Director's determination, the owner or operator of the facility must demonstrate the technology is or will be optimized to minimize impingement mortality of all non-fragile species. The Director must include verifiable and enforceable permit conditions that ensure the

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technology will perform as demonstrated; or

(6) *Systems of technologies as the BTA for impingement mortality.* A facility must operate a system of technologies, management practices, and operational measures, that, after review of the information required in the *impingement technology performance optimization study* at 40 CFR 122.21(r)(6)(ii), the Director determines is the best technology available for impingement reduction at your cooling water intake structures. As the basis for the Director's determination, the owner or operator of the facility must demonstrate the system of technology has been optimized to minimize impingement mortality of all non-fragile species. In addition, the Director's decision will be informed by comparing the impingement mortality performance data under 40 CFR 122.21(r)(6)(ii)(D) to the impingement mortality performance standard that would otherwise apply under paragraph (c)(7) of this section. The Director must include verifiable and enforceable permit conditions that ensure the system of technologies will perform as demonstrated; or

(7) *Impingement mortality performance standard.* A facility must achieve a 12-month impingement mortality performance standard of all life stages of fish and shellfish of no more than 24 percent mortality, including latent mortality, for all non-fragile species together that are collected or retained in a sieve with maximum opening dimension of 0.56 inches and kept for a holding period of 18 to 96 hours. The Director may, however, prescribe an alternative holding period. You must conduct biological monitoring at a minimum frequency of monthly to demonstrate your impingement mortality performance. Each month, you must use all of the monitoring data collected during the previous 12 months to calculate the 12-month survival percentage. The 12-month impingement mortality performance standard is the total number of fish killed divided by the total number of fish impinged over the course of the entire 12 months. The owner or operator of the facility must choose whether to demonstrate compliance with this requirement for the entire facility, or for each individual cooling water intake structure for which this paragraph (c)(7) is the selected impingement mortality requirement.

(8) *Additional measures for shellfish.* The owner or operator must comply with any additional measures, such as seasonal deployment of barrier nets, established by the Director to protect shellfish.

(9) *Additional measures for other species.* The owner or operator must comply with any additional measures, established by the Director, to protect fragile species.

(10) *Reuse of other water for cooling purposes.* This impingement mortality standard does not apply to that portion of cooling water that is process water, gray water, waste water, reclaimed water, or other waters reused as cooling water in lieu of water obtained by marine, estuarine, or freshwater intakes.

(11) *De minimis rate of impingement.* In limited circumstances, rates of impingement may be so low at a facility that additional impingement controls may not be justified. The Director, based on review of site-specific data submitted under 40 CFR 122.21(r), may conclude that the documented rate of impingement at the cooling water intake is so low that no additional controls are warranted. For threatened or endangered species, all unauthorized take is prohibited by the Endangered Species Act of 1973 (16 U.S.C. 1531 *et seq.*). Notice of a determination that no additional impingement controls are warranted must be included in the draft or proposed permit and the Director's response to all comments on this determination must be included in the record for the final permit.

(12) *Low capacity utilization power generating units.* If an existing facility has a cooling water intake structure used for one or more existing electric generating units, each with an annual average capacity utilization rate of less than 8 percent averaged over a 24-month block contiguous period, the owner or operator may request the Director consider less stringent requirements for impingement mortality for that cooling water intake structure. The Director may, based on review of site-specific data concerning cooling water system data under 40 CFR 122.21(r)(5), establish the BTA standards for impingement mortality for that cooling water intake structure that are less stringent than paragraphs (c)(1) through (7) of this section.

(d) *BTA standards for entrainment for existing facilities.* The Director must establish BTA standards for entrainment for each intake on a site-specific basis. These standards must reflect the Director's determination of the maximum reduction in entrainment warranted after consideration of the relevant factors as specified in § 125.98. The Director may also require periodic reporting on your progress towards installation and operation of site-specific entrainment controls. These reports may include updates on planning, design, and construction or other appropriate topics as required by the Director. If the Director determines that the site-specific BTA standard for entrainment under this paragraph requires performance equivalent to a closed-cycle recirculating system as defined at § 125.92(c), then under § 125.94(c)(1) your facility will comply with the impingement mortality standard for that intake.

(e) *BTA standards for impingement mortality and entrainment for new units at existing facilities.* The owner or operator of a new unit at an existing facility must achieve the impingement mortality and entrainment standards provided in either paragraph (e)(1) or (2) of this section, except as provided in paragraph (e)(4) of this section, for each cooling water intake structure used to provide cooling water to the new unit.

(1) *Requirements for new units.* The owner or operator of the facility must reduce the design intake flow for the new unit, at a minimum, to a level commensurate with that which can be attained by the use of a closed-cycle recirculating system for the same level of cooling for the new unit.

(2) *Alternative requirements for new units.* The owner or operator of a new unit at an existing facility must demonstrate to the Director that the technologies and operational measures employed will reduce the level of adverse environmental impact from any cooling water intake structure used to supply cooling water to the new unit to a comparable level to that which would be achieved under § 125.94(e)(1). This demonstration must include a showing that the entrainment reduction is equivalent to 90 percent or greater of the reduction that could be achieved through compliance with § 125.94(e)(1). In addition this demonstration must include a showing that the impacts to fish and shellfish, including important forage and predator species, within the watershed will be comparable to those which would result under the requirements of § 125.94(e)(1).

(3) This standard does not apply to:

(i) Process water, gray water, waste water, reclaimed water, or other waters reused as cooling water in lieu of water obtained by marine, estuarine, or freshwater intakes;

(ii) Cooling water used by manufacturing facilities for contact cooling purposes;

(iii) Portions of those water withdrawals for auxiliary plant cooling uses comprising less than two mgd of the facility's flow; and

(iv) Any quantity of emergency back-up water flows.

(4) The owner or operator of a facility must comply with any alternative

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requirements established by the Director pursuant to § 125.98(b)(7).

(5) For cooling water flows excluded by paragraph (e)(3) of this section, the Director may establish additional BTA standards for impingement mortality and entrainment on a site-specific basis.

(f) *Nuclear facilities.* If the owner or operator of a nuclear facility demonstrates to the Director, upon the Director's consultation with the Nuclear Regulatory Commission, the Department of Energy, or the Naval Nuclear Propulsion Program, that compliance with this subpart would result in a conflict with a safety requirement established by the Commission, the Department, or the Program, the Director must make a site-specific determination of best technology available for minimizing adverse environmental impact that would not result in a conflict with the Commission's, the Department's, or the Program's safety requirement.

(g) *Additional measures to protect Federally-listed threatened and endangered species and designated critical habitat.* The Director may establish in the permit additional control measures, monitoring requirements, and reporting requirements that are designed to minimize incidental take, reduce or remove more than minor detrimental effects to Federally-listed species and designated critical habitat, or avoid jeopardizing Federally-listed species or destroying or adversely modifying designated critical habitat (e.g., prey base). Such control measures, monitoring requirements, and reporting requirements may include measures or requirements identified by an appropriate Field Office of the U.S. Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service during the 60 day review period pursuant to § 125.98(h) or the public notice and comment period pursuant to 40 CFR 124.10. Where established in the permit by the Director, the owner or operator must implement any such requirements.

(h) *Interim BTA requirements.* An owner or operator of a facility may be subject to interim BTA requirements established by the Director in the permit on a site-specific basis.

(i) *More stringent standards.* The Director must establish more stringent requirements as best technology available for minimizing adverse environmental impact if the Director determines that compliance with the applicable requirements of this section would not meet the requirements of applicable State or Tribal law, including compliance with applicable water quality standards (including designated uses, criteria, and antidegradation requirements).

(j) The owner or operator of a facility subject to this subpart must:

(1) Submit and retain permit application and supporting information as specified in § 125.95;

(2) Conduct compliance monitoring as specified in § 125.96; and

(3) Report information and data and keep records as specified in § 125.97.

§ 125.95 Permit application and supporting information requirements.

(a) *Permit application submittal timeframe for existing facilities.* (1) The owner or operator of a facility subject to this subpart whose currently effective permit expires after July 14, 2018, must submit to the Director the information required in the applicable provisions of 40 CFR 122.21(r) when applying for a subsequent permit (consistent with the owner or operator's duty to reapply pursuant to 40 CFR 122.21(d)).

(2) The owner or operator of a facility subject to this subpart whose currently effective permit expires prior to or on July 14, 2018, may request the Director to establish an alternate schedule for the submission of the information required in 40 CFR 122.21(r) when applying for a subsequent permit (consistent with the owner or operator's duty to reapply pursuant to 40 CFR 122.21(d)). If the owner or operator of the facility demonstrates that it could not develop the required information by the applicable date for submission, the Director must establish an alternate schedule for submission of the required information.

(3) The Director may waive some or all of the information requirements of 40 CFR 122.21(r) if the intake is located in a manmade lake or reservoir and the fisheries are stocked and managed by a State or Federal natural resources agency or the equivalent. If the manmade lake or reservoir contains Federally-listed threatened and endangered species, or is designated critical habitat, such a waiver shall not be granted.

(b) *Permit application submittal timeframe for new units.* For the owner or operator of any new unit at an existing facility subject to this subpart:

(1) You must submit the information required in 40 CFR 122.21(r) for the new unit to the Director no later than 180 days before the planned commencement of cooling water withdrawals for the operation of the new unit. If you have already submitted the required information in your previous permit application, you may choose to submit an update to the required information.

(2) The owner or operator is encouraged to submit their permit applications well in advance of the 180 day requirement to avoid delay.

(c) *Permit applications.* After the initial submission of the 40 CFR 122.21(r) permit application studies after October 14, 2014, the owner or operator of a facility may, in subsequent permit applications, request to reduce the information required, if conditions at the facility and in the waterbody remain substantially unchanged since the previous application so long as the relevant previously submitted information remains representative of current source water, intake structure, cooling water system, and operating conditions. Any habitat designated as critical or species listed as threatened or endangered after issuance of the current permit whose range of habitat or designated critical habit includes waters where a facility intake is located constitutes potential for a substantial change that must be addressed by the owner/operator in subsequent permit applications, unless the facility received an exemption pursuant to 16 U.S.C. 1536(o) or a permit pursuant to 16 U.S.C. 1539(a) or there is no reasonable expectation of take. The owner or operator of a facility must submit its request for reduced cooling water intake structure and waterbody application information to the Director at least two years and six months prior to the expiration of its NPDES permit. The owner or operator's request must identify each element in this subsection that it determines has not substantially changed since the previous permit application and the basis for the determination. The Director has the discretion to accept or reject any part of the request.

(d) The Director has the discretion to request additional information to supplement the permit application, including a request to inspect a facility.

(e) *Permit application records.* The owner or operator of a facility must keep records of all submissions that are part of its permit application until the subsequent permit is issued to document compliance with the requirements of this section. If the Director approves a request for reduced permit application studies under § 125.95(a) or (c) or § 125.98(g), the owner or operator of a facility must keep records of all submissions that are part of the previous permit application until the subsequent permit is issued.

(f) In addition, in developing its permit application, the owner or operator of an existing facility or new unit at an existing facility must, based on readily available information at the

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time of the permit application, instead of the information required at § 122.21(r)(4)(vi) of this chapter identify all Federally-listed threatened and endangered species and/or designated critical habitat that are or may be present in the action area.

(g) *Certification.* The owner or operator of a facility must certify that its permit application is true, accurate and complete pursuant to § 122.22(d) of this chapter.

§ 125.96 Monitoring requirements.

(a) *Monitoring requirements for impingement mortality for existing facilities.* The Director may establish monitoring requirements in addition to those specified at § 125.94(c), including, for example, biological monitoring, intake velocity and flow measurements. If the Director establishes such monitoring, the specific protocols will be determined by the Director.

(b) *Monitoring requirements for entrainment for existing facilities.* Monitoring requirements for entrainment will be determined by the Director on a site-specific basis, as appropriate, to meet requirements under § 125.94(d).

(c) *Additional monitoring requirements for existing facilities.* The Director may require additional monitoring for impingement or entrainment including, but not limited to, the following:

(1) The Director may require additional monitoring if there are changes in operating conditions at the facility or in the source waterbody that warrant a re-examination of the operational conditions identified at 40 CFR 122.21(r).

(2) The Director may require additional monitoring for species not subject to the BTA requirements for impingement mortality at § 125.95(c). Such monitoring requirements will be determined by the Director on a site-specific basis.

(d) *Monitoring requirements for new units at existing facilities.* Monitoring is required to demonstrate compliance with the requirements of § 125.94(e).

(1) The Director may establish monitoring requirements for impingement, impingement mortality, and entrainment of the commercial, recreational, and forage base fish and shellfish species identified in the Source Water Baseline Biological Characterization data required by 40 CFR 122.21(r)(4). Monitoring methods used must be consistent with those used for the Source Water Baseline Biological Characterization at 40 CFR 122.21(r)(4). If the Director establishes such monitoring requirements, the frequency of monitoring and specific protocols will be determined by the Director.

(2) If your facility is subject to the requirements of § 125.94(e)(1) or (2), the frequency of flow monitoring and velocity monitoring must be daily and must be representative of normal operating conditions. Flow monitoring must include measuring cooling water withdrawals, make-up water, and blowdown volume. The Director may require additional monitoring necessary to demonstrate compliance with § 125.94(e).

(3) If your facility is subject to the requirements of § 125.94(e)(2), you must monitor to demonstrate achievement of reductions commensurate with a closed-cycle recirculating system. You must monitor entrainable organisms at a proximity to the intake that is representative of the entrainable organisms in the absence of the intake structure. You must also monitor the latent entrainment mortality in front of the intake structure. Mortality after passing the cooling water intake structure must be counted as 100 percent mortality unless you have demonstrated to the approval of the Director that the mortality for each species is less than 100 percent. Monitoring must be representative of the cooling water intake when the structure is in operation. In addition, sufficient samples must be collected to allow for calculation of annual average entrainment levels of all life stages of fish and shellfish. Specific monitoring protocols and frequency of monitoring will be determined by the Director. You must follow the monitoring frequencies identified by the Director for at least two years after the initial permit issuance. After that time, the Director may approve a request for less frequent monitoring in the remaining years of the permit term and when a subsequent permit is reissued. The monitoring must measure the total count of entrainable organisms or density of organisms, unless the Director approves of a different metric for such measurements. In addition, you must monitor the AIF for each intake. The AIF must be measured at the same time as the samples of entrainable organisms are collected. The Director may require additional monitoring necessary to demonstrate compliance with § 125.94(e).

(4) The Director may require additional monitoring for impingement or entrainment at the cooling water intake structure used by a new unit including, but not limited to, the following:

(i) The Director may require additional monitoring if there are changes in operating conditions at the facility or in the source waterbody that warrant a re-examination of the operational conditions identified at 40 CFR 122.21(r).

(ii) The Director may require additional monitoring for species not subject to the BTA requirements for impingement mortality at § 125.95(c). Such monitoring requirements will be determined by the Director on a site-specific basis.

(e) *Visual or remote inspections.* You must either conduct visual inspections or employ remote monitoring devices during the period the cooling water intake structure is in operation. You must conduct such inspections at least weekly to ensure that any technologies operated to comply with § 125.94 are maintained and operated to function as designed including those installed to protect Federally-listed threatened or endangered species or designated critical habitat. The Director may establish alternative procedures if this requirement is not feasible (e.g., an offshore intake, velocity cap, or during periods of inclement weather).

(f) *Request for reduced monitoring.* For facilities that are subject to § 125.94(c)(7) and where the facility's cooling water intake structure does not directly or indirectly affect Federally-listed threatened and endangered species, or designated critical habitat, the owner or operator of the facility may request the Director to reduce monitoring requirements after the first full permit term in which these monitoring requirements are implemented, on the condition that the results of the monitoring to date demonstrate that the owner or operator of the facility has consistently operated the intake as designed and is meeting the requirements of § 125.94(c).

(g) *Additional monitoring related to Federally-listed threatened and endangered species and designated critical habitat at existing facilities.* Where the Director requires additional measures to protect Federally-listed threatened or endangered species or designated critical habitat pursuant to § 125.94(g), the Director shall require monitoring associated with those measures.

§ 125.97 Other permit reporting and recordkeeping requirements.

The owner or operator of an existing facility subject to this subpart is required to submit to the Director the following information:

(a) *Monitoring reports.* Discharge Monitoring Reports (DMRs) (or equivalent State reports) and results of all monitoring, demonstrations, and

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other information required by the permit sufficient to determine compliance with the permit conditions and requirements established under § 125.94.

(b) *Status reports.* Any reports required by the Director under § 125.94.

(c) *Annual certification statement and report.* An annual certification statement signed by the responsible corporate officer as defined in § 122.22 of this chapter subject to the following:

(1) If the information contained in the previous year's annual certification is still pertinent, you may simply state as such in a letter to the Director and the letter, along with any applicable data submission requirements specified in this section shall constitute the annual certification.

(2) If you have substantially modified operation of any unit at your facility that impacts cooling water withdrawals or operation of your cooling water intake structures, you must provide a summary of those changes in the report. In addition, you must submit revisions to the information required at § 122.21(r) of this chapter in your next permit application.

(d) *Permit reporting records retention.* Records of all submissions that are part of the permit reporting requirements of this section must be retained until the subsequent permit is issued. In addition, the Director may require supplemental recordkeeping such as compliance monitoring under § 125.96, supplemental data collection under 40 CFR 122.21, additional monitoring or data collection under § 125.95.

(e) *Reporting.* The Director has the discretion to require additional reporting when necessary to establish permit compliance and may provide for periodic inspection of the facility. The Director may require additional reporting including but not limited to the records required under § 125.97(d).

(f) *Records of Director's Determination of BTA for Entrainment.* All records supporting the Director's Determination of BTA for Entrainment under § 125.98(f) or (g) must be retained until such time as the Director revises the Determination of BTA for Entrainment in the permit.

(g) *Additional reporting requirements related to Federally-listed threatened and endangered species or designated critical habitat.* Where the Director requires additional measures to protect Federally-listed threatened or endangered species or critical habitat pursuant to § 125.94(g), the Director shall require reporting associated with those measures.

§ 125.98 Director requirements.

(a) *Permit application.* The Director must review the materials submitted by the applicant under 40 CFR 122.21(r) for completeness pursuant to 40 CFR 122.21(e) at the time of initial permit application and any application for a subsequent permit.

(b) *Permitting requirements.* Section 316(b) requirements are implemented through an NPDES permit. Based on the information submitted in the permit application, the Director must determine the requirements and conditions to include in the permit.

(1) Such permits, including permits with alternative requirements under paragraph (b)(7) of this section, must include the following language as a permit condition: ''Nothing in this permit authorizes take for the purposes of a facility's compliance with the Endangered Species Act.''

(2) In the case of any permit issued after July 14, 2018, at a minimum, the permit must include conditions to implement and ensure compliance with the impingement mortality standard at § 125.94(c) and the entrainment standard at § 125.94(d), including any measures to protect Federally-listed threatened and endangered species and designated critical habitat required by the Director. In addition, the permit must include conditions, management practices and operational measures necessary to ensure proper operation of any technology used to comply with the impingement mortality standard at § 125.94(c) and the entrainment standard at § 125.94(d). Pursuant to § 125.94(g), the permit may include additional control measures, monitoring requirements, and reporting requirements that are designed to minimize incidental take, reduce or remove more than minor detrimental effects to Federally-listed species and designated critical habitat, or avoid jeopardizing Federally-listed species or destroying or adversely modifying designated critical habitat (e.g. prey base). Such control measures, monitoring requirements, and reporting requirements may include measures or requirements identified by the U.S. Fish and Wildlife Service and/or the National Marine Fisheries Service during the 60 day review period pursuant to § 125.98(h) or the public notice and comment period pursuant to 40 CFR 124.10. The Director may include additional permit requirements if:

(i) Based on information submitted to the Director by any fishery management agency or other relevant information, there are migratory or sport or commercial species subject to entrainment that may be directly or indirectly affected by the cooling water intake structure; or

(ii) It is determined by the Director, based on information submitted by any fishery management agencies or other relevant information, that operation of the facility, after meeting the entrainment standard of this section, would still result in undesirable cumulative stressors to Federally-listed and proposed, threatened and endangered species, and designated and proposed critical habitat.

(3) At a minimum, the permit must require the permittee to monitor as required at §§ 125.94 and 125.96.

(4) At a minimum, the permit must require the permittee to report and keep the records specified at § 125.97.

(5) After October 14, 2014, in the case of any permit issued before July 14, 2018 for which the Director, pursuant to § 125.95(a)(2), has established an alternate schedule for submission of the information required by 40 CFR 122.21(r), the Director may include permit conditions to ensure that, for any subsequent permit, the Director will have all the information required by 40 CFR 122.21(r) necessary to establish impingement mortality and entrainment BTA requirements under § 125.94(c) and (d). In addition, the Director must establish interim BTA requirements in the permit based on the Director's best professional judgment on a site-specific basis in accordance with § 125.90(b) and 40 CFR 401.14.

(6) In the case of any permit issued after October 14, 2014, and applied for before October 14, 2014, the Director may include permit conditions to ensure that the Director will have all the information under 40 CFR 122.21(r) necessary to establish impingement mortality and entrainment BTA requirements under § 125.94(c) and (d) for the subsequent permit. The Director must establish interim BTA requirements in the permit on a site-specific basis based on the Director's best professional judgment in accordance with § 125.90(b) and 40 CFR 401.14.

(7) For new units at existing facilities, the Director may establish alternative requirements if the data specific to the facility indicate that compliance with the requirements of § 125.94(e)(1) or (2) for each new unit would result in compliance costs wholly out of proportion to the costs EPA considered in establishing the requirements at issue, or would result in significant adverse impacts on local air quality, significant adverse impacts on local water resources other than impingement

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or entrainment, or significant adverse impacts on local energy markets:

(i) The alternative requirements must achieve a level of performance as close as practicable to the requirements of § 125.94(e)(1);

(ii) The alternative requirements must ensure compliance with these regulations, other provisions of the Clean Water Act, and State and Tribal law;

(iii) The burden is on the owner or operator of the facility requesting the alternative requirement to demonstrate that alternative requirements should be authorized for the new unit.

(8) The Director may require additional measures such as seasonal deployment of barrier nets, to protect shellfish.

(c) *Compliance schedule.* When the Director establishes a schedule of requirements under § 125.94(b), the schedule must provide for compliance with § 125.94(c) and (d) as soon as practicable. When establishing a schedule for electric power generating facilities, the Director should consider measures to maintain adequate energy reliability and necessary grid reserve capacity during any facility outage. These may include establishing a staggered schedule for multiple facilities serving the same localities. The Director may confer with independent system operators and state public utility regulatory agencies when establishing a schedule for electric power generating facilities. The Director may determine that extenuating circumstances (e.g., lengthy scheduled outages, future production schedules) warrant establishing a different compliance date for any manufacturing facility.

(d) *Supplemental Technologies and Monitoring.* The Director may require additional technologies for protection of fragile species, and may require additional monitoring of species of fish and shellfish not already required under § 125.95(c). The Director may consider data submitted by other interested parties. The Director may also require additional study and monitoring if a threatened or endangered species has been identified in the vicinity of the intake.

(e) *Impingement technology performance optimization study.* The owner or operator of a facility that chooses to comply with § 125.94(c)(5) or (6) must demonstrate in its *impingement technology performance optimization study* that the operation of its impingement reduction technology has been optimized to minimize impingement mortality of non-fragile species. The Director may request further data collection and information as part of the *impingement technology performance optimization study,* including extending the study period beyond two years. The Director may also consider previously collected biological data and performance reviews as part of the study. The Director must include in the permit verifiable and enforceable permit conditions that ensure the modified traveling screens or other systems of technologies will perform as demonstrated. The Director may waive all or part of the *impingement technology performance optimization study* at 40 CFR122.21(r)(6) after the first permit cycle wherein the permittee is deemed in compliance with § 125.94(c).

(f) *Site-specific entrainment requirements.* The Director must establish site-specific requirements for entrainment after reviewing the information submitted under 40 CFR 122.21(r) and § 125.95. These entrainment requirements must reflect the Director's determination of the maximum reduction in entrainment warranted after consideration of factors relevant for determining the best technology available for minimizing adverse environmental impact at each facility. These entrainment requirements may also reflect any control measures to reduce entrainment of Federally-listed threatened and endangered species and designated critical habitat (e.g. prey base). The Director may reject an otherwise available technology as a basis for entrainment requirements if the Director determines there are unacceptable adverse impacts including impingement, entrainment, or other adverse effects to Federally-listed threatened or endangered species or designated critical habitat. Prior to any permit reissuance after July 14, 2018, the Director must review the performance of the facility's installed entrainment technology to determine whether it continues to meet the requirements of § 125.94(d).

(1) The Director must provide a written explanation of the proposed entrainment determination in the fact sheet or statement of basis for the proposed permit under 40 CFR 124.7 or 124.8. The written explanation must describe why the Director has rejected any entrainment control technologies or measures that perform better than the selected technologies or measures, and must reflect consideration of all reasonable attempts to mitigate any adverse impacts of otherwise available better performing entrainment technologies.

(2) The proposed determination in the fact sheet or statement of basis must be based on consideration of any additional information required by the Director at § 125.98(i) and the following factors listed below. The weight given to each factor is within the Director's discretion based upon the circumstances of each facility.

(i) Numbers and types of organisms entrained, including, specifically, the numbers and species (or lowest taxonomic classification possible) of Federally-listed, threatened and endangered species, and designated critical habitat (e.g., prey base);

(ii) Impact of changes in particulate emissions or other pollutants associated with entrainment technologies;

(iii) Land availability inasmuch as it relates to the feasibility of entrainment technology;

(iv) Remaining useful plant life; and

(v) Quantified and qualitative social benefits and costs of available entrainment technologies when such information on both benefits and costs is of sufficient rigor to make a decision.

(3) The proposed determination in the fact sheet or statement of basis may be based on consideration of the following factors to the extent the applicant submitted information under 40 CFR 122.21(r) on these factors:

(i) Entrainment impacts on the waterbody;

(ii) Thermal discharge impacts;

(iii) Credit for reductions in flow associated with the retirement of units occurring within the ten years preceding October 14, 2014;

(iv) Impacts on the reliability of energy delivery within the immediate area;

(v) Impacts on water consumption; and

(vi) Availability of process water, gray water, waste water, reclaimed water, or other waters of appropriate quantity and quality for reuse as cooling water.

(4) If all technologies considered have social costs not justified by the social benefits, or have unacceptable adverse impacts that cannot be mitigated, the Director may determine that no additional control requirements are necessary beyond what the facility is already doing. The Director may reject an otherwise available technology as a BTA standard for entrainment if the social costs are not justified by the social benefits.

(g) *Ongoing permitting proceedings.* In the case of permit proceedings begun prior to October 14, 2014 whenever the Director has determined that the information already submitted by the owner or operator of the facility is sufficient, the Director may proceed with a determination of BTA standards for impingement mortality and

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entrainment without requiring the owner or operator of the facility to submit the information required in 40 CFR 122.21(r). The Director's BTA determination may be based on some or all of the factors in paragraphs (f)(2) and (3) of this section and the BTA standards for impingement mortality at § 125.95(c). In making the decision on whether to require additional information from the applicant, and what BTA requirements to include in the applicant's permit for impingement mortality and site-specific entrainment, the Director should consider whether any of the information at 40 CFR 122.21(r) is necessary.

(h) The Director must transmit all permit applications for facilities subject to this subpart to the appropriate Field Office of the U.S. Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service upon receipt for a 60 day review prior to public notice of the draft or proposed permit. The Director shall provide the public notice and an opportunity to comment as required under 40 CFR 124.10 and must submit a copy of the fact sheet or statement of basis (for EPA-issued permits), the permit application (if any) and the draft permit (if any) to the appropriate Field Office of the. Fish and Wildlife Service and/or Regional Office of the National Marine Fisheries Service. This includes notice of specific cooling water intake structure requirements at § 124.10(d)(1)(ix) of this chapter, notice of the draft permit, and any specific information the Director has about threatened or endangered species and critical habitat that are or may be present in the action area, including any proposed control measures and monitoring and reporting requirements for such species and habitat.

(i) *Additional information.* In implementing the Director's responsibilities under the provisions of this subpart, the Director is authorized to inspect the facility and to request additional information needed by the Director for determining permit conditions and requirements, including any additional information from the facility recommended by the Services upon review of the permit application under paragraph (h) of this section.

(j) Nothing in this subpart authorizes the take, as defined at 16 U.S.C. 1532(19), of threatened or endangered species of fish or wildlife. Such take is prohibited under the Endangered Species Act unless it is exempted pursuant to 16 U.S.C. 1536(o) or permitted pursuant to 16 U.S.C. 1539(a). Absent such exemption or permit, any facility operating under the authority of this regulation must not take threatened or endangered wildlife.

(k) The Director must submit at least annually to the appropriate EPA Regional Office facilities' annual reports submitted pursuant to § 125.97(g), for compilation and transmittal to the Services.

§ 125.99 [Reserved]

[FR Doc. 2014–12164 Filed 8–14–14; 8:45 am]

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FPL's response to Staff's First Set of Interrogatories Nos. 1-17.

Additional files contained on Staff Hearing Exhibits CD for No. 3 Supplemental.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 36
PARTY: STAFF – (DIRECT)
DESCRIPTION: Michael W. Sole(1-2, 4-6, 16)Juan E. Enjamio(3) Renae B. Deaton(5,

QUESTION:
Please refer to paragraph 7 of the MTHS petition. If the MTHS or a similar project is not approved, how frequently are scheduled maintenance outages at the PFM during manatee season expected to cause FPL to fail to meet its environmental requirements?

RESPONSE:
Maintenance and planned outages are scheduled based on factors associated with the operation of generating units and their associated equipment. As an example, combustion turbine maintenance requirements are based on a unit's service hours, cycles of operation, and operational diagnostic monitoring in compliance with manufacturer best operating practices. Similarly, steam turbine maintenance outages are scheduled based on unit operation and condition assessment. Outages to perform maintenance are generally shorter in duration and occur more frequently than planned outages, which involve major component replacements and refurbishments requiring several days to weeks to complete. FPL must conduct maintenance and planned outages during periods where system loads are low enough to accommodate the temporary removal of generating unit capability while at the same time maintaining sufficient reserve margin. The period in which planned and maintenance outages are scheduled includes the majority of the manatee season (November 15 - March 31). To the extent feasible, FPL's planned outages avoid the period spanning the end of the December through January period as this is the time where most of the winter system peaks associated with extreme cold weather occur. A review of the 2016/2017 and 2017/2018 periods showed that the Fort Myers Unit 2 steam turbines were on planned and maintenance outages on average 25.6% of the Manatee Season. Steam turbine availability is critical as cooling water used to condense steam from the turbines generates warm water as required to provide a manatee refuge. FPL cannot know in advance whether cold weather events will occur during a planned outage, which is why the MTHS is required.

In addition, while FPL maintains a top-performing forced outage factor in the utility industry, an unplanned outage can occur at any time. FPL must accommodate unplanned outages while planning those strategies, which will provide adequate protection for manatees in compliance with its manatee protection plan.

QUESTION:
Please refer to paragraph 8 of the MTHS petition. If the MTHS or a similar project is not approved, how frequently is PFM expected to be uneconomically dispatched during manatee season in order to meet its environmental requirements?

RESPONSE:
Dispatch of PFM Unit 2 to provide heated discharge water for manatee heating purposes during periods of reserve shutdown would result in system operations running the unit out of economic dispatch. As discussed in the response to Staff's Interrogatory No. 1, the periods outside of the summer peak are where system loads are lower resulting in fewer generating units being needed to meet the demand. As described in FPL's petition, the addition of more efficient combined cycle units and solar generation to FPL's generating unit portfolio has resulted in decreases in PFM Unit 2 unit dispatch and is projected to continue to do so as lower cost units are dispatched first. FPL projections used for preparation of the 10 Year Site Plan filing identifies that PFM Unit 2 show a 13% reduction of operation during the manatee season by the year 2027. While FPL cannot predict when a cold day event will occur, the projected decrease in unit dispatch results in an associated increase of 13% in the probability that the unit would not be operating during manatee season. Additionally, PFM Unit 2 would not be available to operate economically or uneconomically during periods of planned or unplanned outages.

QUESTION:
Please refer to paragraph 8 of the MTHS petition. For each year of the remaining life of the PFM units, please provide the following information in Excel.

a. **The annual average estimated fuel costs of each FPL generating unit.**
b. **The estimated capacity factor for the PFM units for the duration of manatee season.**

RESPONSE:
Please see Attachment No. 1 to this response, which shows the requested information for the remaining depreciation service life of the PFM units. FPL has no plans for the retirement of PFM's Unit 2 (the combined cycle unit) at this time.

QUESTION:
Please refer to paragraph 9 of the MTHS petition. What would happen to the installed electric MTHS if conditions change and PFM is dispatched more frequently?

RESPONSE:
The installed electric MTHS would remain in place and be available for utilization during planned or unplanned outages that would occur during manatee season (November 15 - March 31). Due to PFM's location, farther north than many of FPL's plants with manatee protection plans, the probability of requiring the heater is significantly increased. The Cape Canaveral Clean Energy Center, which is the northernmost FPL plant with a manatee protection plan, also has a permanently installed MTHS.

QUESTION:
Please refer to paragraph 9 of the MTHS petition. Has FPL explored any other option besides the electric MTHS to maintain compliance with its environmental permit requirements? If yes, please describe each other option and provide the CPVRR of each option considered. If no, please explain why not.

RESPONSE:
Yes. Based on FPL's experiences at other facilities, FPL has found that the electric MTHS, such as the heater system installed at the Cape Canaveral Clean Energy Center, to be the best, most reliable method for meeting the manatee protection plan requirement for providing a warm water refuge for manatees during the manatee season. This system is reliable, easy to operate so that no trained operators are required, does not generate air emissions, and is always available and already in place when manatee season approaches. FPL explored one other option besides the electric MTHS, which was to rent a diesel-fueled temporary MTHS which uses boilers to supply the heat for the system. The diesel-fueled MTHS would have to be rented from November - March each year at an estimated cost of $645,000 per year as it is needed to be in place if an outage occurred while the ambient water temperature was below 61°F. One-time cost to install the supporting infrastructure (piping, foundation, wiring, secondary fuel containment, etc.) is estimated at $800,000.

Costs for mobilization and demobilization of the MTHS, on-site operators, and general operations and maintenance are estimated at $162,000 per year. The cost of diesel fuel to operate the MTHS and disposal cost is estimated to be $135,000 per year. Diesel-fired boilers are not readily available, and finding them when needed, has proven to be difficult in the past.

The CPVRR for both options is shown below. The CPVRR of installing the electric-powered MTHS is $5,148,300 less than the cost of renting the diesel-fueled MTHS.

CPVRR Analysis ($000)

	CPVRR	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028 - 2036
Cost of Renting Heaters												
Rent Expense	$ 10,931.2	$ 94.2	$ 961.0	$ 980.2	$ 999.8	$ 1,019.8	$ 1,040.2	$ 1,061.0	$ 1,082.2	$ 1,103.9	$ 1,126.0	$ 11,203.0
Property Tax and Insurance	102.6	14.4	14.4	13.5	12.7	11.8	11.0	10.1	9.3	8.4	7.6	33.9
Depreciation	452.7	2.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	47.1	374.4
Interest Expense	91.0	0.6	15.1	14.1	13.2	12.3	11.3	10.4	9.6	8.7	7.8	31.6
Return on Equity	290.3	1.9	48.2	45.1	42.0	39.1	36.2	33.3	30.5	27.7	24.9	100.7
Income Tax	98.6	0.7	16.4	15.3	14.3	13.3	12.3	11.3	10.4	9.4	8.5	34.2
Cost of Renting Heaters	**$ 11,966.4**	**$ 113.9**	**$ 1,102.1**	**$ 1,115.3**	**$ 1,129.1**	**$ 1,143.3**	**$ 1,158.0**	**$ 1,173.3**	**$ 1,189.0**	**$ 1,205.2**	**$ 1,221.8**	**$ 11,777.7**
Cost of Installing Heaters												
Operating Expense	348.1	3.0	30.6	31.2	31.8	32.5	33.1	33.8	34.5	35.1	35.9	356.7
Property Tax and Insurance	641.2	90.2	89.9	84.6	79.3	74.0	68.7	63.4	58.1	52.8	47.5	212.0
Depreciation	2,829.4	13.1	294.1	294.1	294.1	294.1	294.1	294.1	294.1	294.1	294.1	2,339.9
Interest Expense	568.9	3.8	94.4	88.3	82.4	76.6	70.9	65.3	59.8	54.3	48.9	197.3
Return on Equity	1,814.5	12.2	301.0	281.7	262.7	244.2	226.0	208.1	190.6	173.2	155.8	629.2
Income Tax	616.0	4.1	102.2	95.6	89.2	82.9	76.7	70.7	64.7	58.8	52.9	213.6
Cost of Installing Heaters	**$ 6,818.1**	**$ 126.3**	**$ 912.2**	**$ 875.5**	**$ 839.6**	**$ 804.3**	**$ 769.5**	**$ 735.4**	**$ 701.7**	**$ 668.4**	**$ 635.1**	**$ 3,948.6**
Net Cost (Savings) of Installing	**$ (5,148.3)**	**$ 12.4**	**$ (189.8)**	**$ (239.8)**	**$ (289.5)**	**$ (339.0)**	**$ (388.5)**	**$ (437.9)**	**$ (487.3)**	**$ (536.8)**	**$ (586.8)**	**$ (7,829.0)**

Note: The 2018 rental expense excludes the $250,000 of sunk costs for the March 2018 rental. Property tax and insurance, depreciation, interest, return on equity and income tax costs of renting the diesel-fueled MTHS represents the revenue requirements for the one-time costs associated with installing the supporting infrastructure (installed cost of $800,000)

QUESTION:
Please refer to paragraph 10 of the MTHS petition.
a. How did FPL calculate the estimated $250,000 in O&M expenses of the temporary diesel-burning system in 2018, including a breakdown by equipment rental and fuel?
b. What is the estimated service duration of the electric MTHS?
c. How did FPL calculate the estimated $5 million capital cost and $30,000 annual O&M expenses for the electric MTHS?

RESPONSE:

a. The estimated O&M expenses assumed a total of 7 days (the average number of days the heaters might be expected to run annually based on historical information) of 24 hour per day operation of the MTHS. The operating costs for the MTHS included equipment rental and operational costs of approximately $144,000 and projected fuel cost of $121,800 for a total of $265,800. The operational costs included labor costs associated with the boiler operators who are necessary to operate the boilers.

b. FPL estimates the duration of the electric MTHS system to be for the life of the plant as it will be required to meet the requirements of the Manatee Protection Plan.

c. At the present time, final contracts for the construction of the PFM MTHS are not complete. The capital and O&M cost estimates were based on FPL's experience gained from constructing and operating similar MTHS's (temporary and permanent systems) at the Cape Canaveral Clean Energy Center, the Riviera Beach Clean Energy, and the Port Everglades Clean Energy Center.

QUESTION:
Please refer to paragraph 2 of the NPDES petition.
a. When does FPL anticipate the NPDES permit conditions and compliance schedules will be imposed on Plant Scherer by the Environmental Protection Division of Georgia's Department of Natural Resources?
b. Please identify with pinpoint citation the specific regulation(s) that FPL anticipates will be imposed on Plant Scherer.

RESPONSE:

a. Based on the information received from Georgia Power Company, a draft permit is expected to be issued by the Georgia Department of Natural Resources Environmental Protection Division (Georgia EPD) in the third or fourth quarter of 2018. A final permit could be issued within 2-3 months after the draft permit is issued. However, if the permit is appealed the final permit would be stayed until resolution of the appeal.

b. FPL anticipates Georgia EPD will use the methodology found in Georgia Department of Natural Resources Rule 391-3-6-.06(4)(d)5(ii) of the Georgia Rules and Regulations to develop a site-specific effluent limitation that will be imposed on Plant Scherer. This effluent limitation will be protective of the copper water quality standard found at Georgia Rule 391-3-6-.03(5)(e)(ii)5.(a).

QUESTION:
Please refer to paragraph 3 of the NPDES petition. Is Plant Scherer currently in compliance with existing water quality standards for copper discharges?

RESPONSE:
Plant Scherer is in compliance with its existing NPDES permit requirements. Georgia's water quality standard for copper applies to State waters, which in this case is the Ocmulgee River. Based on water quality data collected by GPC and submitted with its NPDES permit renewal application, the effluent being discharged from the Plant's NPDES outfall has the reasonable potential to cause an exceedance of the water quality standard for copper in the Ocmulgee River. The blowdown from the cooling towers for the Plant's four units is the primary contributor to copper in the effluent.

QUESTION:
Please refer to paragraph 3 of the NPDES petition. Please describe what FPL means by a "reasonable potential to exceed Georgia's prescribed water quality standards."

RESPONSE:
The Georgia Environmental Protection Division NPDES Reasonable Potential Procedures provides the following:

"40 CFR 122.44(d) of the Clean Water Act requires delegated States to develop procedures for determining whether a discharge causes, has the reasonable potential to cause, or contributes to an instream excursion above a narrative or numeric criteria within a State water. If such reasonable potential is determined to exist, the NPDES permit must contain pollutant effluent limits and/or effluent limits for whole effluent toxicity. Georgia's Reasonable Potential Procedures are based on Georgia's Rules and Regulations for Water Quality Control (Rules), Chapter 391-3-6-.06(4)(d)5. The chemical specific and biomonitoring data and other pertinent information in EPD's files will be considered in accordance with the review procedures specified in the Rules in the evaluation of a permit application and in the evaluation of the reasonable potential for an effluent to cause an exceedance in the numeric or narrative criteria."
https://epd.georgia.gov/sites/epd.georgia.gov/files/related_files/site_page/REASONABLE%20POTENTIAL%202003.pdf

Based on the applicable regulations and scenario described in FPL's response to Staff's Interrogatory No. 7 a and b, there is a reasonable potential that Georgia's water quality standard for copper of 5 parts per billion, which applies in the Ocmulgee River, will be exceeded unless the condenser tubes are replaced and cooling towers are repacked for Plant Scherer's four units.

QUESTION:
Please refer to paragraph 9 of the NPDES petition. How much does Plant Scherer Unit 4 contribute to the overall copper contamination levels in comparison to Units 1-3? As part of your response, please provide the analysis supporting this contribution percentage.

RESPONSE:
The goal of the copper reduction strategy is to enable any one unit to operate in an unconstrained condition without regard to another unit's operations. This allows the plant's discharge to always be protective of the water quality standard for copper regardless of how many units are online or the operating conditions of any given unit. To accomplish this, all four units will complete identical projects to replace condenser tube and cooling tower packing material as scheduled. No one unit will be able to forgo any replacement project since that would jeopardize the overall result for all units. In addition, this will prevent any unit from placing any portion of its individual compliance burden on another unit.

With regard to Unit 4's contribution of copper relative to that of the other units, it is not possible to quantify that in a meaningful way as unit concentrations are not additive. That is, one unit's contribution to the whole is greatly dependent on the rate and frequency of cooling tower blowdown, both of which vary significantly over the course of a single day and are driven by unit operations and dispatch. The highly variable and non-additive nature of these concentrations illustrates why all units will perform identical projects to focus on individual unit performance.

QUESTION:
Please refer to paragraph 11 of the NPDES petition.
a. How will the costs of the project be allocated to Plant Scherer 4? If the cost contribution percentage is different than the contamination contribution percentage, please explain why.
b. How will the costs of the project be allocated between the owners of Plant Scherer 4? If the allocation is different than the ownership percentage, please explain why.

RESPONSE:

a. The cooling tower is defined by the joint operating agreement as a unit specific piece of equipment. As such, expenditures incurred with unit specific equipment are allocated based on the Scherer 4 ownership percentage. Replacement of cooling tower packing material for each Scherer unit will be paid for by that unit's respective owners.

b. Scherer 4 is jointly owned by FPL (76.36%) and JEA (23.64%). Accordingly, FPL will incur 76.36% of the project costs associated with the replacement of the Scherer 4 cooling tower packing.

QUESTION:
Please refer to paragraph 11 of the NPDES petition. Please identify and describe the options that Georgia Power considered. As part of this response, please provide the CPVRR of each option considered.

RESPONSE:
Georgia Power, as Plant Scherer operating agent, considered four alternatives: chemical treatment options; condenser tube coating; cooling tower blowdown waste water treatment; and replacement of condenser tubes and cooling tower packing material. As explained below, chemical treatment and condenser tube coating were rejected as ineffective for achieving the necessary copper reduction. Georgia Power did not perform a CPVRR evaluation of the remaining two alternatives, but it is clear from the cost estimates shown below that replacement of the condenser tubes and cooling tower packing material is a much less expensive alternative.

1. Chemical Treatment. Attempts to mitigate the elevated copper concentrations included investigating, testing and evaluating the effectiveness of corrosion inhibitors in the condenser and biocide treatments of the cooling tower packing/fill. The trials indicated that the desired copper discharge reduction was not achieved, so this alternative was rejected.

2. Condenser Tube Coating. Condenser tube coating has been used to extend condenser tube life. It was also considered as a mechanism to reduce the quantity of copper that is corroded from the tubes, which would reduce the copper concentration in the cooling tower blowdown. This method utilizes an application of epoxy coating to fill pits, crevices and similar anomalies in the condenser tube walls. Thick applications are used to coat the entire surface forming a protective barrier between the cooling water stream and the tube metal, which reduces the copper corrosion. However, this alternative had several negative attributes that resulted in Georgia Power rejecting it:
   - Useful life of coating is only about two years;
   - Coating does not improve tube wall integrity; in fact surface preparation prior to each coating/recoating poses a risk to tube wall integrity, thus increasing the risk of tube leaks;
   - Coating reduces heat transfer performance of condenser and therefore increases the generating unit's heat rate; and
   - There was only a single supplier for the coating, introducing availability and price risks.

   If Georgia Power had decided to proceed with condenser tube coating, it would not have addressed the issue of copper releases from the cooling tower packing material.

3. Cooling Tower Blowdown Waste Water Treatment - Installation of a site common wastewater treatment system to remove copper from the combined cooling tower blowdown streams prior to entering the NPDES pond was evaluated. The technology is available but the scale of the system required for Plant Scherer is very large (12,000 gallons per minute). A system of that size would have both a high initial capital cost (estimated at $100 million; FPL share about $19 million) and high continuing O&M costs (estimated at $4 million per year; FPL share about $0.75 million per year).

4. Replacement of Condenser Tubes & Tower Packing/Fill - The point source of the elevated copper discharge is the copper tube material in the condenser. As the tubing corrodes, copper is released into the circulating water system. It then gets entrained in the biological growth that naturally accumulates on the cooling tower packing/fill material. Since this growth inhibits the thermal efficiency of the cooling tower, it is treated with biocides, which cause it to fall to the cooling tower basin thus releasing accumulated copper into the circulating water system and the blowdown. The ultimate remedy of this issue is the replacement of both the condenser tubes and the cooling tower packing material. As noted in the petition to modify the NPDES Permit Renewal Requirement Project, FPL does not seek to include the costs it incurred for the Unit 4 copper condenser tube replacement as part of this request because replacement of those tubes (unlike the repacking) was needed as part of regular maintenance. FPL's share of the cost to repack the Unit 4 cooling tower is approximately $9 million (capital) with minimal annual O&M.

QUESTION:
Please refer to paragraph 11 of the NPDES petition. Is the repacking of cooling towers a regular maintenance item? If so, how often is it performed and what performance characteristics are affected?

RESPONSE:
No. Complete repacking of the cooling tower is not a regular maintenance item, though Georgia Power has replaced some small portions of cooling tower packing material over time as a result of uneven spacing and deformation that developed since original installation. In the absence of the need to reduce copper concentrations in the wastewater there would be no need for full-scale replacement of the Scherer Unit 4 cooling tower packing at this time.

QUESTION:
Please refer to paragraph 12 of the NPDES petition. How did Georgia Power determine that the change in cooling tower packing will decrease the copper contaminant levels? As part of your response, please describe whether FPL independently verified that the repacking will decrease copper contaminant levels. If yes, how? If no, why not?

RESPONSE:
As discussed in detail in FPL's response to Staff's 1st Set of Interrogatories No. 12, GPC, as operating agent, conducted a technical analysis and concluded the primary source of the copper was from the copper tubes contained in the condenser, which carried over to the cooling tower and was entrained in the cooling tower packing/fill. Data collected after the condenser tubes were replaced in the Unit 3 condensers but without repacking that unit's cooling tower showed that the copper concentration in the cooling tower blowdown did not decrease meaningfully. The only remaining source of the copper is the cooling tower packing material, in which copper from the cooling tower remains entrained. Therefore, GPC has reasonably concluded that repacking the cooling tower is necessary and sufficient to achieve the intended reduction in the copper contaminant level FPL has reviewed GPC's conclusions as well as the supporting data that GPC has provided and believes that GPC's conclusions are reasonable.

QUESTION:
Please refer to paragraph 13 of the NPDES petition.
a. When is monitoring scheduled to begin?
b. What is the estimated annual cost of monitoring? As part of this response, please identify the amount that will be allocated to FPL and how that allocation was estimated.
c. Will other contaminants also be monitored as part of this scheduled monitoring?

RESPONSE:

a. The monitoring expected to be required by the new NPDES permit would begin immediately upon the effective date of the permit.

b. The annual cost associated with the additional monitoring for copper expected in the new NPDES permit is not anticipated to be material or a significant increase from current monitoring practices or costs. The amount allocated to FPL will be based on its common ownership share at Plant Scherer which is 19.09%. The 19.09% is calculated by taking 25% (1 of 4 units) multiplied by 76.36% (FPL's ownership).

c. No. GPC and FPL expect that copper will be the sole focus of the monitoring required by the new NPDES permit. However, as with any NPDES permit renewal, Georgia EPD may choose to include additional pollutants that it believes necessary following their review of the permit application.

QUESTION:
Please refer to paragraph 14 of the NPDES petition. How did FPL calculate the estimated $9 million for cooling tower repacking?

RESPONSE:
FPL calculated its ownership obligation by taking the total Unit 4 cooling tower repacking project estimate provided by GPC, as operating agent ($12 million) and multiplying it by FPL's ownership share in Unit 4 (76.36%). The result is $9.163 million, which FPL rounded to $9 million.

QUESTION:
Please refer to paragraph 14(b) of the NPDES petition. How does the proposal meet the requirement at page 7 of Order No. PSC-94-0044-FOF-EI, issued in Docket No. 930613-EI on January 1, 1994, that "such costs are not recovered through some other cost recovery mechanism or through base rates?" Specifically, please indicate how the costs associated with this change in the permit will not be recovered through base rates.

RESPONSE:
As discussed in FPL witness Sole's testimony filed April 2, 2018, FPL could not have included in its most recent base rate MFRs the repacking costs that it is incurring to comply with anticipated NPDES permit renewal requirements at Plant Scherer. Those MFRs were prepared in late 2015 and early 2016. At that time, Georgia Power had not completed its evaluation of the copper concentration in the Plant Scherer effluent, much less determined the appropriate way to address the need to reduce the copper concentration. No other cost recovery mechanism is available to recover these types of costs.

Please note that, while ECRC recovery is appropriate for repacking costs, FPL is proposing accounting treatment for those costs that will avoid ECRC recovery until the Georgia EPD issues a final NPDES renewal permit requiring a reduction in copper concentration. As discussed in FPL witness Deaton's testimony filed April 2, 2018, prior to obtaining permit renewal, FPL will exclude the costs incurred for the repacking activity at Plant Scherer Unit 4 from ECRC recoverable accounts and instead will record those costs in base capital accounts and associated expenses will be recorded in base expense accounts. Once the renewed NPDES permit is issued (thus confirming the regulatory requirements for the repacking activity), FPL will transfer the balance of costs for the repacking activity from the base capital accounts to ECRC recoverable accounts and begin the normal process of ECRC recovery for those and future reasonable and prudent associated capital costs and O&M expenses.

DECLARATION

I sponsored the answer to Interrogatory Nos. 1, 2, 4 and 6 through 16 and co-sponsored No. 5 from **STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-17)** to Florida Power & Light Company in Docket No. 20180007-EI. The responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and the interrogatory answers identified above, and that the facts stated therein are true.

Michael W. Sole

Date: 5/7/2018

DECLARATION

I sponsored the answer to Interrogatory No. 3 from **STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-17)** to Florida Power & Light Company in Docket No. 20180007-EI. The responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and the interrogatory answers identified above, and that the facts stated therein are true.

Juan E. Enjamio

Date: 4/30/18

DECLARATION

I sponsored the answer to Interrogatory No. 17 and co-sponsored No. 5 from **STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-17)** to Florida Power & Light Company in Docket No. 20180007-EI. The responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and the interrogatory answers identified above, and that the facts stated therein are true.

Renae B. Deaton

Date: May 7, 2018

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FPL's response to Staff's Third Set of Interrogatories Nos. 20-27.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 37
PARTY: STAFF – (DIRECT)
DESCRIPTION: Michael W. Sole

QUESTION:
For the following questions please refer to Renae B. Deaton's April 2, 2018 Testimony. Substation Discharge

Please refer to page 6, lines 12-15. What caused the delays in obtaining equipment clearances? Please identify each such delay and its respective duration.

RESPONSE:
FPL Distribution substation transformers that require regasketing repairs must be de-energized prior to maintenance, meaning the required energy load must be picked up by the other transformers in the substation or at nearby substations. FPL has completed the majority of work on all of the leaking equipment that can easily be de-energized. During 2017, FPL was unable to de-energize the Distribution substation transformers that required regasketing repairs. Warmer temperatures created more demand for energy, the transformers in question are critical to providing energy to FPL customers in their particular areas, and the required energy load could not be switched to other transformers without putting FPL's grid in jeopardy.

FPL is working to alleviate this energy load problem in its critical substations by utilizing a mobile transformer that would temporarily take over the load for the transformers in need of repairs. FPL is also adding additional transformers to critical substations to reduce the overall load on each transformer. This will allow FPL to complete regasketing repairs on its critical transformers.

QUESTION:
For the following questions please refer to Renae B. Deaton's April 2, 2018 Testimony. Manatee Plant Reburn

Please refer to page 7, lines 14-17. What caused the postponement of the Manatee Unit 1 overhaul?

RESPONSE:
Due to system capacity needs, a shortened outage to address critical equipment repairs was conducted on Manatee Unit 1 to address reliability concerns and return the unit to service earlier than originally projected. It was determined during the shortened outage that the remaining maintenance activities originally planned during the outage could be postponed to the next planned major unit outage with minimal risk to unit reliability.

QUESTION:
For the following questions please refer to Renae B. Deaton's April 2, 2018 Testimony. National Pollutant Discharge Elimination System (NPDES)

Please refer to page 10, lines 21-23. Why was an accelerated schedule implemented?

RESPONSE:
The schedule was accelerated because Phase 1 of the Chlorine Optimization Study, which involved baseline water sampling and analyses and literary research to identify potential options to minimize chlorine use, was completed earlier than anticipated. Therefore, the project moved on to Phase 2, which involves testing of potential chlorine optimization options.

QUESTION:
For the following questions please refer to Michael W. Sole's April 2, 2018 Testimony. Manatee Temporary Heating System (MTHS)

Please refer to page 10, lines 8-9. What temperature, or temperature range, does FPL consider to be "extremely cold conditions" that would trigger the use of the third heater?

RESPONSE:
Based on historical data gathered about the site and the information submitted in FPL's Florida Department of Environmental Protection and United States Army Corps of Engineers permit applications, conditions would be considered "extremely cold" if the following continued for a duration of 6 or more days: a wind speed of 20 mph or greater from the north, a minimum water temperature of 50°F, and a minimum ambient air temperature of 40°F.

QUESTION:
For the following questions please refer to Michael W. Sole's April 2, 2018 Testimony. NPDES For Questions 24 and 25, please refer to page 16, lines 11-15.

How often is testing and monitoring of the effluent from the cooling tower basin conducted?

RESPONSE:
Plant Scherer's Unit 4 cooling tower basin blowdown is sampled and analyzed on a weekly basis to trend copper levels over a range of operating conditions. The plant's NPDES Outfall 01A, where cooling tower blowdown from all four units combines with ash transport bleed-off, is sampled and analyzed for copper approximately twice a month.

QUESTION:
For the following questions please refer to Michael W. Sole's April 2, 2018 Testimony.
For Questions 24 and 25, please refer to page 16, lines 11-15.
When was the most recent testing and what were the results?

RESPONSE:
Outfall 01A (from the NPDES Collection Basin) was sampled on May 29, 2018 and found to have a copper concentration of 93.5 ppb.

FPL notes that repacking the Unit 4 cooling tower has had a substantial beneficial impact on the copper concentration in the cooling tower blowdown. The Unit 4 cooling tower blowdown had been sampled on March 8, 2018, just prior to the scheduled outage in which replacement of the cooling tower packing material was performed. That sample showed a copper concentration of 91.4 ppb. Following unit startup after the outage, the blowdown was sampled on May 29, 2018 and the copper concentration had dropped to 24.7 ppb.

Over time, as the condenser retubing and cooling tower repacking from all four Scherer units is completed, GPC and FPL expect that the copper concentration measured at Outfall 01A will fall to below the calculated limit of 60 ppb referenced on page 16, line 8 of Mr. Sole's April 2, 2018 testimony.

QUESTION:
For the following questions please refer to Michael W. Sole's April 2, 2018 Testimony.
For Questions 24 and 25, please refer to page 16, lines 11-15.
Please refer to page 16, lines 19-20. Why will EPD require monitoring of the copper concentrations?

RESPONSE:
Georgia EPD will require monitoring of the copper concentration under the new NPDES permit to more fully assess the impact of the plant's effluent on the Ocmulgee River under a broad range of conditions. This additional monitoring will enable EPD to ensure that the effluent does not cause an exceedance of the Georgia Water Quality Standard (WQS) and that the plant is making progress toward achieving the expected permit limitation and compliance schedule.

QUESTION:
For the following questions please refer to Michael W. Sole's April 2, 2018 Testimony.
For Questions 24 and 25, please refer to page 16, lines 11-15.
Please refer page 18, lines 10-16. Please describe the benefits and drawbacks, if any, of using titanium tubes?

RESPONSE:
Titanium tubing offers multiple benefits with very few, if any, drawbacks. Titanium has superior strength-to-weight ratio and high resistance to corrosion and erosion. These factors allow thinner-walled condenser tubes enabling better heat transfer. Additionally, unlike copper, titanium does not leach into cooling tower blowdown or plate out on turbine blades. Such tubing has been used in power plant condensers since the early 1970s, and testing performed by other U.S. utilities has shown that it performs well in this application. One drawback to such tubing, though, is the potential for biofouling, but this is easily controlled with the use of chlorination and/or tube cleaning measures.

DECLARATION

I sponsored the answer to Interrogatory No. 20 from **STAFF'S THIRD SET OF INTERROGATORIES (Nos. 20-27)** to Florida Power & Light Company in Docket No. 20180007-EI. The response is true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and the interrogatory answers identified above, and that the facts stated therein are true.

Michael Wan

Date: 6-13-18

DECLARATION

I sponsored the answer to Interrogatory No. 21 from **STAFF'S THIRD SET OF INTERROGATORIES (Nos. 20-27)** to Florida Power & Light Company in Docket No. 20180007-EI. The response is true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and the interrogatory answers identified above, and that the facts stated therein are true.

Charles R. Rote

Date: 6/13/18

DECLARATION

I sponsored the answers to Interrogatory Nos. 22 through 27 from **STAFF'S THIRD SET OF INTERROGATORIES (NOS. 20-27)** to Florida Power & Light Company in Docket No. 20180007-EI. The responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and the interrogatory answers identified above, and that the facts stated therein are true.

Michael W. Sole

Date: 6/18/2018

38

FPL's response to Staff's Fourth Set of Interrogatories Nos. 28-31.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 38
PARTY: STAFF – (DIRECT)
DESCRIPTION: Michael W. Sole

QUESTION:
FPL Estimated/Actual Discovery Questions

Turkey Point Cooling Canal. Please refer to FPL witness Deaton's July 25, 2018 testimony page 6, lines 17-20. Please identify each activity that was deferred from 2017 to 2018, including the respective expenditures and project(s).

RESPONSE:
The following required activities were deferred from 2017 to 2018:

Sediment Removal	$3.2 million	State of Florida Consent Order
Recovery Well System	$2.3 million	State of Florida Consent Order
Nutrient Management Plan/Algae Control & Remediation	$1.0 million	State of Florida Consent Order
Monitoring/Mitigation/Reporting/CSEM & Project Support	1.9 million	Miami-Dade County Consent Agreement
Groundwater Monitoring Clusters to Model Conditions in Model Land Basin	$1.1 million	Miami-Dade Consent Agreement Addendum
Total	**$9.5 million**	

QUESTION:
FPL Estimated/Actual Discovery Questions

NPDES Permit Renewal Requirements. Please refer to FPL witness Deaton's July 25, 2018 testimony page 7, lines 1-9. How were the pumps determined to be cost effective in optimizing the chlorine use in the intake cooling system?
a. What other methods were explored by FPL and why were they rejected?
b. When did chlorine optimization become a requirement of the industrial wastewater permit?

RESPONSE:
One of the findings of the chlorine optimization study required by the Florida Department of Environmental Protection (FDEP) identified that the existing St. Lucie sodium hypochlorite (bleach) injection system resulted in excessive chlorination as a result of the single bleach pump that had a limited turn-down rate (i.e., the bleach injection system could not be reduced to a more optimal level). In order to reduce the bleach feed to the Intake Cooling Water (ICW) System, two smaller pumps were needed that could provide proper control for both costs (bleach used) and effective biological control. The cost estimates for the pump installation were approximately $280,000 and the subsequent reduced cost of bleach is approximately $188,000 per year. Based on the estimated cost savings that would be achieved by the second year, FPL determined that it was cost effective to install the ICW bleach pump immediately.

a. PSL contracted with a consultant to undertake a Florida Department of Environmental Protection (FDEP) required chlorine optimization study. Following a review of plant operations and a literature search, it was determined that the options under consideration for chlorine optimization are:

1. Optimize the PSL sodium hypochlorite (bleach) injection system, feed strategy, and monitoring/control.
2. Determine, via a pilot study, whether or not chlorine dioxide can be used in lieu of bleach as a more effective and efficient biocide.

Both options are being pursued.

The option of installing a dechlorination skid prior to the discharge point was also investigated, but was generally rejected based on determination that it would not be cost-effective. Other alternative biocides were briefly evaluated (such as Buckman's Oxamine (Monochloramine or MCA), but were similarly rejected due to cost-effectiveness.

b. VI.5 of Permit FL0002208-017, issued November 4, 2016 by the Florida Department of Environmental Protection required PSL to complete a chlorine optimization study, as identified in witness Sole's July 19, 2017 testimony.

QUESTION:
FPL Estimated/Actual Discovery Questions

Avian Monitoring. Please refer to FPL witness Sole's June 13, 2018 testimony page 5, lines 9-15. Please provide a breakdown of the O&M expenditures that are associated with the SSAMR project in both 2018 and 2019.

RESPONSE:
The breakdown for 2018 is $69,775.00 and 2019 is $103,491.00. Additional cost information is provided in FPL's response to Interrogatory No. 31.

QUESTION:
FPL Estimated/Actual Discovery Questions

Avian Monitoring. Please refer to FPL witness Sole's June 13, 2018 testimony page 6, lines 12-14. Please identify the SSAMR project scope, budget, schedule and the costs associated with the avian monitoring program.

RESPONSE:
Please see the below table with information on the project scope, budget and costs associated with the avian monitoring program. The monitoring activities are scheduled to begin in 2018 and conclude in 2019.

Task	Description	Cost Estimate
Task 1 - Mobilization and Kickoff Meeting	Meeting at the DeSoto facility to review the proposed scope of work, schedule, logistics, and reporting.	$2,860
Task 2 - Searcher Efficiency Trials	Four searcher efficiency trials, each conducted prior to seasonal mortality monitoring events. Deployment of 30 carcasses, dedicated team of three searchers (including two search dogs) each season.	$8,860
Task 3 - Scavenging and Carcass Removal Trials	Four carcass persistence trials, one per season. Deployment of 30 carcasses, installation of trail cameras, and 28 days of camera and pedestrian monitoring of carcass persistence during each season.	$58,800
Task 4 - Mortality Monitoring	Mortality monitoring and data collection will be conducted through pedestrian surveys of the 23-mile (60-acre) sampling fraction using a combination of biologists and trained dogs comprising 3 teams. A total of 30 surveys are proposed during 2018.	$92,940
Task 5 – Data Analysis and Reporting	Statistical analysis using the *Carcass* package to calculate annual and seasonal fatality estimates. Annual report including dates, durations, and results of all mortality monitoring, discussion of potential influence of covariant factors, photographs, maps, and field data. Additional reporting, as necessary, through the USFWS AIMRS database (SPUT reporting).	$9,810
	TOTAL	**$173,270**

DECLARATION

I sponsored the answers to Interrogatory Nos. 28 through 31 from **STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 28-31)** to Florida Power & Light Company in Docket No. 20180007-EI. The responses are true and correct based on my personal knowledge.

Under penalties of perjury, I declare that I have read the foregoing declaration and the interrogatory answers identified above, and that the facts stated therein are true.

Michael W. Sole

Date: 9/14/2018

39

FPL's response to Staff's Second Request for Production of Documents No. 2.

(Confidential DN. 04235-2018)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 39
PARTY: STAFF – (DIRECT)
DESCRIPTION: Michael W. Sole

40

Gulf's response to Staff's First Set of Interrogatories Nos. 1-4.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 40
PARTY: STAFF – (DIRECT)
DESCRIPTION: Richard M. Markey

For the following questions please refer to Richard M. Markey's April 2, 2018 Testimony

Emissions Monitoring

1. Please refer to page 3, lines 14-21. Please identify each expense for the emissions monitoring program including those associated with Quality Assurance/Quality Control, Relative Accuracy Test Audits, and Linearity tests.

ANSWER:

Line Item 1.5, Emission Monitoring, includes the following:

Test Trailer	$ 27,000
Relative Accuracy Test Audits	$ 152,000
CEMS, Emission Monitoring, & Linearities	$ 258,000
General & Miscellaneous	$ 280,000
TOTAL	$ 717,000

Air Quality Compliance

2. Refer to page 5, lines 17-19. Please identify the specific line item costs of ammonia, urea, limestone and the general operation and maintenance activities associated with Air Quality Compliance Program.

ANSWER:

For 2017, ammonia cost was $370,000, carbon and bromine was $216,000 and limestone cost was $7,844,000. Other general operation and maintenance cost includes the following: Crist O&M $9,401,000, Daniel O&M $4,937,000, Scherer O&M $994,000 and other Environmental O&M $71,000 (numbers rounded to nearest 1,000).

3. Please refer to page 6, lines 7-10. Please identify the regulatory and legislative developments regarding the Air Quality Compliance Program that Gulf encountered after FPSC Order No. PSC-10-0683-FOF-EI was issued.

ANSWER:

Since the 2010 Florida Public Service Commission (FPSC) approval of the Daniel SCRs through the ECRC in FPSC Order No. PSC-10-0683-FOF-EI, there were a number of regulatory developments related to the Daniel SCRs.

NOx CAIR/Transport/CSAPR: On August 8, 2011, the EPA adopted the Cross-State Air Pollution Rule (CSAPR) to replace CAIR effective January 1, 2012. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit stayed the CSAPR rule and on August 21, 2012, vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement rule. On April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015. On October 26, 2016, the EPA published a final rule that updates the CSAPR ozone-season NOx program, which completely removed Florida from all CSAPR programs, left the Georgia seasonal NOx budget unchanged, and established more stringent NOx emissions budgets in Mississippi.

Ozone: On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. On October 1, 2015, the EPA finalized the National Ambient Air Quality Standards (NAAQS) for ozone, which lowered the standard to 70 ppb. On November 16, 2017, the EPA published initial air quality designations, for most areas of the United States, for the 2015 ozone standards. On December 20, 2017, the EPA sent responses to the States regarding designations for the 2015 NAAQS for ozone (70 ppb). EPA did not designate any area in Mississippi as nonattainment.

Crist Water Conservation

4. Please refer to page 6, lines 18-22. What are the projected maintenance activities that were postponed to 2018. Please also explain why each activity was postponed.

ANSWER:

Gulf projected costs in 2017 for replacing the Plant Crist reclaimed water system filters and strainers; however, this work was postponed due to a decrease in system utilization. In addition, Gulf was able to limit the amount of contract work required to maintain the system.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause.	))	Docket No. 20180007-EI

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF ESCAMBIA

Before me, the undersigned authority, personally appeared Richard M. Markey, who being first duly sworn, deposes and says that he is the Director of Environmental Affairs of Gulf Power Company, a Florida corporation, that Gulf Power Company's Answers to Interrogatories 1-9 in the Staff's First, Second and Third Sets of Interrogatories to Gulf Power Company are true and correct to the best of his knowledge and belief. He is personally known to me.

Richard M. Markey
Director of Environmental Affairs

Sworn to and subscribed before me this 25th day of October, 2018.

Melissa Darnes
Notary Public, State of Florida at Large

MELISSA DARNES
MY COMMISSION # FF 912598
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

41

Gulf's response to Staff's Second Set of Interrogatories Nos. 5-7.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 41
PARTY: STAFF – (DIRECT)
DESCRIPTION: Richard M. Markey

5. **Air Quality Compliance**. Please refer to Gulf witness Markey's July 25, 2018 testimony page 4, line 12 through page 5, line 4.
   a. Please identify each Air Quality Compliance program project and its respective cost breakdown.
   b. Please verify whether costs associated with Plant Crist Groundwater Characterization and Remediation project are reflected in the Air Quality Compliance Program and if so, please explain why.

ANSWER:

a.

Description	Re-projected 2018 Spend
Crist 6 SCR	1,102,561
Crist Scrubber	5,308,681
Crist Groundwater Charact & Remed	3,879,879
Daniel Scrubber	1,135,326
Scherer Unit 3 SCR	213,500
Scherer Unit 3 Scrubber	257,490
Schereer Unit 3 Baghouse	488,281
	12,385,718

b. Yes, costs associated with the Plant Crist Groundwater Characterization and Remediation Project are included in Gulf's Air Quality Compliance Program. The costs are associated with groundwater impacts around the Plant Crist gypsum storage area that was constructed as part of the Plant Crist scrubber project. The Plant Crist scrubber project investment costs are included in Gulf's Air Quality Compliance Program as approved by Commission Order No. PSC-07-0721-S-EI in Docket No. 070007- EI.

6. **Air Quality Compliance.** Please refer to Gulf witness Markey's July 25, 2018 testimony page 4, lines 18-22. Please describe the components, including the costs of each component, of the corrective action plan.
   a. Please provide the regulation that Gulf will be addressing with the corrective action plan, also identify which agency is enforcing the regulation.

ANSWER:

The corrective action plan includes:
- A brief description of site history and current groundwater conditions
- An overview of the proposed groundwater remediation system, including:
  - Key components of the proposed remediation system
  - Proposed monitoring and reporting associated with the remediation system.

The remediation system components include: (1) remediation system design and construction oversight; (2) electrical, mechanical, and conveyance system infrastructure; and (3) the remediation system (including multi-media filtration, iron removal system, cartridge filtration, and onsite laboratory). The cost of each component is as follows:
- Remediation system design and construction oversight: $521,512
- Electrical, mechanical, and conveyance system construction: $1,467,258
- Remediation system construction (including multi-media filtration, iron removal system, cartridge filtration, and onsite laboratory): $251,469

a. As required by the Plant Crist National Pollutant Discharge Elimination System (NPDES) Industrial Wastewater Permit (Permit No. FL0002275), Gulf Power monitors site groundwater and reports groundwater results to the Florida Department of Environmental Protection (FDEP). In response to elevated groundwater concentrations detected in the NPDES groundwater monitoring network around the Plant Crist gypsum storage area, FDEP issued a letter on September 22, 2017, requiring Gulf Power to submit a corrective action plan outlining proposed actions appropriate to address this issue. The NPDES permit is authorized by the Clean Water Act and enforced by FDEP.

7. **Coal Combustion Residual.** Please refer to Gulf witness Markey's July 25, 2018 testimony page 7, lines 9-10. When was the Plant Smith dewatering wastewater treatment system placed in-service? If it is not yet in-service, please provide the date it is estimated to begin operation.

ANSWER:

The Plant Smith dewatering wastewater treatment system is located on-site and is in the commissioning and start-up phase. Gulf expects the system to be placed in-service during September 2018.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause.) Docket No. 20180007-EI

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF ESCAMBIA

Before me, the undersigned authority, personally appeared Richard M. Markey, who being first duly sworn, deposes and says that he is the Director of Environmental Affairs of Gulf Power Company, a Florida corporation, that Gulf Power Company's Answers to Interrogatories 1-9 in the Staff's First, Second and Third Sets of Interrogatories to Gulf Power Company are true and correct to the best of his knowledge and belief. He is personally known to me.

Richard M. Markey
Director of Environmental Affairs

Sworn to and subscribed before me this 25th day of October, 2018.

Melissa Darnes
Notary Public, State of Florida at Large

MELISSA DARNES
MY COMMISSION # FF 912698
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

42

Gulf's response to Staff's Third Set of Interrogatories Nos. 8-9.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 42
PARTY: STAFF – (DIRECT)
DESCRIPTION: Richard M. Markey

8. **Cooling Water Intake Structure (CWIS)**. Please refer to Gulf witness Markey's direct testimony from August 24, 2018, page 3, lines 16-22.
   a. When does Gulf anticipate that the 316(b) compliance strategy and design will be approved by the state environmental agencies?
   b. When does Gulf expect to install the lower capacity intake pumps at Plant Smith Unit 3?

ANSWER:

a. Gulf anticipates receiving approval for the Plant Smith 316(b) compliance strategy with the next NPDES industrial wastewater permit renewal. Gulf expects the permit renewal to be issued in 2019.

b. Gulf expects to install the new lower capacity intake pumps during fourth quarter 2019.

9. **CWIS.** Please refer to Gulf witness Markey's direct testimony from August 24, 2018, page 4, lines 4-5.
   a. Please identify and describe the costs associated with each activity that make up the $2M in forecasted expenses.

ANSWER:

a. The projected 2019 expenditures for the Plant Smith 316(b) cooling water intake structure (CWIS) project include the following:

Pumps	$660,000
Motors	$220,000
Electrical and structure modifications	$720,000
Contract Labor	$400,000
Total	$2,000,000

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause.) Docket No. 20180007-EI

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF ESCAMBIA

Before me, the undersigned authority, personally appeared Richard M. Markey, who being first duly sworn, deposes and says that he is the Director of Environmental Affairs of Gulf Power Company, a Florida corporation, that Gulf Power Company's Answers to Interrogatories 1-9 in the Staff's First, Second and Third Sets of Interrogatories to Gulf Power Company are true and correct to the best of his knowledge and belief. He is personally known to me.

Richard M. Markey

Richard M. Markey
Director of Environmental Affairs

Sworn to and subscribed before me this 25th day of October, 2018.

Melissa Darnes

Notary Public, State of Florida at Large

MELISSA DARNES
MY COMMISSION # FF 912598
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

43

Duke's response to Staff's First Set of Interrogatories Nos. 1-6.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 43
PARTY: STAFF – (DIRECT)
DESCRIPTION: Tim Hill(1)Jeffery Swartz(2-3)Patricia Q. West (4-6)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20180007-EI

Dated: June 14, 2018

DUKE ENERGY FLORIDA, LLC's RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-6)

Duke Energy Florida, LLC ("DEF"), responds to Staff's First Set of Interrogatories to DEF (Nos. 1-6), as follows:

INTERROGATORIES

For the following questions, please refer to Timothy Hill's April 2, 2018 Testimony.

CCR Project

1. Please refer to page 3, lines 8-11. What caused the lower costs for FGD Blowdown Pond closure plan development, vegetation management for CCR facilities, engineering inspections and emergency action plan exercises?

Answer:

• FGD Blowdown Pond Closure Plan Development - The actual costs incurred by the contractor were lower due to synergies from combining the development of closure plans for other stations.

• Vegetation Management for CCR Facilities - CCR facilities at Crystal River include the FGD Blowdown Ponds and the Ash Storage and Disposal Area. Costs were lower than expected due to DEF negotiating a lower rate by using a single contractor to perform vegetation management for the FGD Blowdown ponds as well as other ponds at the Crystal River site.

• Inspections - Annual third party inspections required by the CCR Rule for the FGD Blowdown Ponds and the Ash Storage and Disposal Areas were lower than anticipated due to actual pricing received at time of contract award being less than anticipated.

• Emergency Action Plan Exercises - In 2017, the required expenses associated with Emergency Action Plan Support were slightly reduced by leveraging a support process

developed to support the Duke Energy fleet, as well as reduced printing costs associated with required hardcopy plan maintenance.

For the following questions, please refer to Jeffrey Swartz's April 2, 2018 Testimony.

CAIR Crystal River Project

2. Please refer to page 3, lines 18-20.

   a. Please explain how DEF was able to attain favorable labor costs.

   b. Please explain how DEF was able to attain lower materials costs.

   c. How long does DEF anticipate that it will continue to receive these favorable, lower costs?

Answer:

a. The 2017 labor favorability was primarily due to the timing of Clean Air employee labor vacancies, which resulted in lower labor expense.

b. The lower materials expense was primarily due lower than projected material consumptions for repairs and maintenance.

c. DEF does not anticipate continued labor favorability into calendar year 2018 because the vacant positions have been filled as of December 31, 2017.

3. Please refer to page 4, lines 9-11. Please explain beneficial use sales pricing and its relation to the gypsum expense.

Answer:

DEF has a long-term gypsum sales agreement with United States Gypsum Company ("USG") which currently beneficially uses 100% of the gypsum produced at Crystal River.
USG markets the gypsum for use at its wallboard manufacturing facility in Jacksonville, FL and any remaining volume is sold at market price for use in the production of cement and in agriculture. DEF supports transportation costs and receives revenue from the sale to third parties. This allows DEF to avoid higher cost landfill alternatives while also receiving profit sharing benefits from these sales; proceeds from these sales are applied to DEF's gypsum expense, thereby reducing the net gypsum expense to customers.

For the following questions, please refer to Witness Patricia Q. West's April 2, 2018, Testimony.

Transmission and Distribution Substation Environmental

4. Please refer to page 3, lines 23-24. Please provide the anticipated timeline for the completion of the repairs to the substations.

Answer:

Central Florida Substation – Repairs began at Central Florida Substation on June 5, 2018. Completion is anticipated in July 2018. Remediation activities will follow repair completions.

East Clearwater Substation – The substation rebuild project, repairs and circuit breaker replacement project will begin in the Fall of 2018. Repair completion is anticipated in December 2019. Remediation activities will follow repair completions.

Holder Substation – Repairs are scheduled to begin June 25, 2018, with completion anticipated in August 2018. Remediation activities will follow repair completions.

Kenneth City Substation – Remediation activities were completed June 5, 2018, and remediation report preparation is in progress for submittal to the FDEP.

Tarpon Springs Substation – The substation expansion project, repairs, and circuit breaker replacements are planned for 2018 through December 2019. Remediation activities will follow repair completions.

5. Please refer to page 4, lines 3-6. When will the circuit breaker replacement project be completed?

Answer:

Wekiva Substation – The circuit breaker replacement project has been completed, and remediation activities resumed on June 11, 2018.

Clean Air Compliance Plan

6. Please refer to page 7, lines 17-20. Please identify and describe the compliance strategies that are under development and the respective regulations to which each applies.

Answer:

The compliance strategies are associated with the federal rulemaking activities provided in Section IV.C of the Integrated Clean Air Compliance Plan:

• 316(b): 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. 20170007-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. The Crystal River ("CR") Units 4 and 5 NPDES permit renewal application is currently under review by the Florida Department of Environmental Protection. An application for renewal of the NPDES permit for CR Units 1 and 2, which also includes CR Unit 3 and the Citrus Combined Cycle station, will be submittal to the Florida Department of Environmental Protection in October 2018.

• Steam Electric Effluent Limitation Guidelines ("ELG"): On September 30, 2015, the EPA finalized the updated ELG, 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. The compliance schedule for CR Units 4 and 5 is also being evaluated under the NPDES permit renewal currently under review.

• Coal Combustion Residuals (CCR): 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, and in April 2018 DEF performed 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 2018 and beyond.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 13th day of June, 2018, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared TIM S. HILL, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number 1, from STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS.1-6) in Docket No. 20180007-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13 day of June, 2018.

Tim Hill

Lisa Wilkinson
Notary Public
State of North Carolina

My Commission Expires:
January 23, 2023

Lisa Wilkinson Notary Public Iredell County, NC

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 11th day of June, 2018, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JEFFREY SWARTZ, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 2 and 3, from STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS.1-6) in Docket No. 20180007-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11th day of June, 2018.

Jeffrey Swartz

Barbara Martinuzzi
Notary Public
State of Florida

My Commission Expires:

May 10, 2021

BARBARA MARTINUZZI
MY COMMISSION # GG 080341
EXPIRES: May 10, 2021
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 7th day of June, 2018, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared PATRICIA Q. WEST, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 4, 5, and 6, from STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS.1-6) in Docket No. 20180007-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of June, 2018.

Patricia Q. West

Patricia Q. West

Notary Public
State of Florida

My Commission Expires:

Christine M. Kaniecki
NOTARY PUBLIC
STATE OF FLORIDA
Comm# GG175767
Expires 1/16/2022

44

Duke's response to Staff's Second Set of Interrogatories Nos. 7-10.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 44
PARTY: STAFF – (DIRECT)
DESCRIPTION: Tim Hill(7)Jeffery Swartz(8-10)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20180007-EI

Dated: September 17, 2018

DUKE ENERGY FLORIDA, LLC's RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 7-10)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Second Set of Interrogatories to DEF (Nos. 7-10), as follows:

INTERROGATORIES

7. **Coal Combustion Residuals.** Please refer to DEF witness Hill's July 25, 2018 testimony, page 2, lines 15-16. Was DEF in danger of not meeting the compliance date requirement if the dewatering and solids removal had not been escalated? If yes, please explain why.

Answer:

As DEF continued to develop the project plan, it was identified that accelerating the FGD Blowdown Pond dewatering and solids removal process was a prudent precaution to mitigate the risk that potential events, such as severe weather and storms, could impact the compliance date. The acceleration of these activities into 2018 does not increase the overall project cost; it is merely a shift of spending from 2019 to 2018. Dewatering of the ponds is required prior to removing solids. This water is pumped to the station's industrial wastewater ponds that rely on percolation and evaporation. The water levels in these industrial wastewater ponds has been high this year, and a period of heavy rain or a storm can render these ponds unable to receive the water from the FGD Blowdown ponds. This could result in the need for more costly alternative disposal options or could jeopardize the compliance date.

8. **CAIR/CAMR.** Please refer to DEF witness Swartz's July 25, 2018 testimony, page 2, lines 16-19. Please provide the reason for the rejection of the alternative methods investigated.

Answer:

Seven treatment options, including the selected option, were evaluated for Crystal River North flue gas desulfurization wastewater:

1. Physical/chemical treatment and direct discharge to surface water;
2. Physical/chemical treatment, biological treatment, and direct discharge to surface Water;
3. Physical/chemical treatment and discharge to groundwater;
4. Physical/chemical treatment, biological treatment, and discharge to groundwater;
5. Physical/chemical treatment and deep well injection;
6. Physical/chemical treatment, biological treatment, and deep well injection; and
7. Physical/chemical treatment, evaporation, crystallization, and landfill disposal.

• Option #4 was selected as the preferred treatment.

• The treatment technology for Option #2 is comparable to selected Option #4, but direct discharge to surface water under Option #2 was less favorable with respect to compliance margin and ability to recover from process upsets.

• Options #1 and #3 were eliminated, because they would not achieve compliance with applicable environmental regulations.

• Options #5 and #6 were unfavorable due to various operational challenges including equipment reliability, recovery from process upsets, limited operating experience, and uncertainties related to suitable injection locations and number of wells required.

• Option #7 was unfavorable primarily due to economics.

9. **FGD Blowdown.** Please refer to DEF witness Swartz's July 25, 2018 testimony, page 3, lines 4-8. Please provide a breakdown of the capital costs using the categories listed.

Answer:

DEF estimates 2018 capital costs of $45,000,558 for the CR4 and 5 FGD Blowdown wastewater project. These costs are for Mechanical-Electrical construction, including buildings and site work, remaining underground construction, start-up/commissioning, and construction oversight.

Mechanical-Electrical Construction	$17.8M
Equipment Procurement	$ 9.8M
Underground Construction	$ 7.7M
Start-up/Commissioning	$ 1.7M
Construction Oversight	$ 3.7M
Engineering and other costs	$ 4.3M
Total	$45.0M

20180007-EI Staff Hearing Exhibits 00069

10. **FGD Blowdown**. Please refer to DEF witness Swartz's July 25, 2018 testimony, page 3, lines 12-13. Please provide evidence to support the statement that extremely wet conditions that exceeded the de-watering efforts were the primary source for the increase in costs.

Answer:

The primary driver of the increase in 2018 expenditures is the grouting work and associated labor and equipment to mitigate risks associated with the Process Chemical Unloading Sump ("Sump") excavation work, of approximately $2.4 million, due to unforeseen underground conditions. The Sump is installed at a depth of approximately 28 feet. During the excavation process for the Sump, extensive abnormal ground water intrusion began and continued to increase, creating ground collapse anomalies. In response, DEF contracted both a geotechnical engineering firm and an underground construction contractor to help resolve the groundwater intrusion and related issues. The resolution identified and implemented was the grouting work for the Sump foundation.

Additionally, weather events, such as storms and lightning strikes, have resulted in over 390 duration hours of delays due to the weather-related work stoppages.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 10th day of September, 2018, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared TIMOTHY HILL, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number 7 from STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC. (NOS. 7-10) in Docket No. 20180007-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 10 day of September, 2018.

Timothy Hill

Beth Jenkins Horsley
Notary Public
Gaston County
North Carolina
My Commission Expires 8/25/2021

Notary Public
State of North Carolina

My Commission Expires:
08-25-2021

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 10th day of September, 2018, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JEFFREY SWARTZ, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 8, 9, and 10, from STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC. (NOS. 7-10) in Docket No. 20180007-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 10th day of September, 2018.

Jeffrey Swartz

Notary Public
State of Florida

My Commission Expires:

July 18, 2022

DEANNA LEE CARVER
Commission # GG 239923
Expires July 18, 2022
Bonded Thru Troy Fain Insurance 800-385-7019

45

Duke's response to Staff's Third Set of Interrogatories Nos. 11-12.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 45
PARTY: STAFF – (DIRECT)
DESCRIPTION: Tim Hill

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause

Docket No. 20180007-EI

Dated: October 4, 2018

DUKE ENERGY FLORIDA, LLC's RESPONSE TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 11-12)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Third Set of Interrogatories to DEF (Nos. 11-12), as follows:

INTERROGATORIES

11. **Flue Gas Desulfurization (FGD).** Please refer to DEF witness Hill's direct testimony from August 24, 2018, page 2, line 24.

a. Please identify and describe the costs associated with each activity that make up the $4.1M in forecasted O&M expenses.

Answer:

Costs for closure of the FGD ponds are estimated to be approximately $3.7M. Costs will cover activities such as solids excavation, transportation and disposal; dewatering and pumping for water management; demolition of existing piping, valves, vaults, pumps and electrical infrastructure; site work including grading, erosion and sediment control measures and site restoration; and project oversight, management and controls.

Costs for various maintenance and repair work required for the CR ash landfill and FGD ponds to comply with the rule are estimated to be approximately $0.2M. These include fixing ruts and animal burrows, vegetation management, erosion repairs, fugitive dust mitigation, Emergency Action Plan exercises and updates, routine weekly inspections, and annual inspections of the landfill and FGD ponds by qualified engineers.

Costs for groundwater monitoring for ash management units are estimated to be approximately $0.2M. These include engineering, sampling, analysis, and reporting for groundwater quality monitoring and also assessment of corrective measures and alternative source demonstrations to address groundwater quality exceedances.

12. **FGD.** Please refer to DEF witness Hill's direct testimony from August 24, 2018, page 3, lines 13-23.

a. Please identify the date on which DEF ceased placing waste in the FGD Blowdown Pond.

b. What steps did DEF take to implement the written closure plan?

c. Was DEF required by any state agency standard to complete any steps as a prerequisite to completing the FGD Blowdown Pond closure? If yes, please identify: (1) the name of the state agency; (2) what the required steps were, and; (3) the cost of compliance.

Answer:

a. The FGD Blowdown Ponds are still in service and will remain in service until the FGD Wastewater Treatment Plant is placed in service. However DEF stopped wastewater flows to the Primary FGD Blowdown Pond on May 17, 2018 and diverted flows to the Backup FGD Blowdown Pond. DEF plans to continue to operate the FGD Blowdown Ponds in this configuration until the ponds are taken out of service.

b. DEF started implementation of the written closure plan with dewatering and utilizing appropriate equipment and methods to excavate and move the CCR to the on-site Ash Storage/Disposal Area. Dewatering of the Primary FGD Blowdown Pond started on May 14, 2018 and solids excavation from the Primary FGD Blowdown Pond started on July 9, 2018.

c. Currently there are two requirements imposed by the Florida Department of Environmental Protection (FDEP) related to completing the FGD Blowdown Pond Closure.

First, DEF is required to provide the FDEP written notice ("Abandonment Plan") at least 60 days before inactivation or abandonment of a wastewater facility or activity and shall

20180007-EI Staff Hearing Exhibits 00075

specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. This is required by Rule 62-620.610, Florida Administrative Code, which lists the General Permit Conditions for all wastewater permits, and which is incorporated by reference in the Conditions of Certification PA 77-09 for the Crystal River Energy Complex. This Abandonment Plan will be prepared from the written closure plans and project documentation that have or will have already been developed.

Secondly, DEF is also required to submit a letter to the FDEP to request an amendment of the details and specifications of the post-closure conditions of the Conditions of Certification PA-77-09 to address Environmental Resource Permit (ERP) rules and criteria. DEF does not anticipate any additional project costs related to the development of this letter.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 3rd day of October, 2018, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared TIMOTHY HILL, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 11 and 12 from STAFF'S THIRD SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC. (NOS. 11-12) in Docket No. 20180007-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of October, 2018.

JULIE D. COLE NOTARY PUBLIC BUNCOMBE COUNTY, NC

Timothy Hill

Notary Public
State of North Carolina

My Commission Expires:
December 19th 2018

46

TECO's response to Staff's First Set of Interrogatories Nos. 1-7.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 46
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope Rusk

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	))	DOCKET NO. 20180007-EI FILED: JUNE 14, 2017

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST SET OF INTERROGATORIES (NOS. 1-7)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 1-7) propounded and served on May 25, 2018, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180007-EI
INDEX TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-7)

Number	Witness	Subject	Bates Stamped Page
1	Rusk	Please refer to page 6, lines 9-11. Please identify the actual maintenance costs for the ductwork and cooling towers.	1
2	Rusk	Please refer to page 6, lines 15-17. a. What caused the decrease of cogeneration purchases? b. Why was a lower allowance rate for SO2 used and what was that rate?	2
3	Rusk	Please refer to page 7, lines 7-11. Please identify a. the number of outages including the duration, and b. the number and duration of hurricane related start-up delays.	3
4	Rusk	Please refer to page 7, lines 13-16. Please describe the work, if any, that was completed on the Big Bend Unit 4 SOFA project in 2017.	4
5	Rusk	Please refer to page 7, lines 20-22. What type of work was performed on the secondary air dampers? Please explain why this work was not anticipated in the projections for the cost of the project.	5
6	Rusk	Please refer to page 7, line 24 through page 8 line 2. Please explain why the cost to replace bearings was not anticipated in the projections for the cost of the project.	6
7	Rusk	Refer to page 9, lines 6-12. Please provide a pinpoint citation to the FDEP Site Rehabilitation Completion Order language requiring the removal and abandonment of wells and injection equipment.	7

Penelope Rusk
Manager, Rates

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

For the following questions please refer to Penelope A. Rusk's April 2, 2018 Testimony

Big Bend Unit 3 Flue Gas

1. Please refer to page 6, lines 9-11. Please identify the actual maintenance costs for the ductwork and cooling towers.

A. The actual maintenance cost for the cooling towers and ductwork for Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration project was $730,167. There was maintenance performed on all four cooling towers and associated ductwork. Of the twenty-one tasks performed, seven tasks were for the cooling towers at a cost of $426,751, and fourteen tasks were for ductwork including duct inlets and outlets, at a cost of $303,416. The Big Bend Unit 3 FGD Integration project included some other activities which were less costly than projected and partially offset the costs of the ductwork and cooling towers maintenance, and the total Big Bend Unit 3 FGD Integration project variance of $192,685 was largely due to this ductwork and cooling tower maintenance activity.

SO2 Emissions Allowances

2. Please refer to page 6, lines 15-17.
a. What caused the decrease of cogeneration purchases?

b. Why was a lower allowance rate for SO2 used and what was that rate?

A. a. The phrase "less cogeneration purchases than projected" refers to the dollars of SO2 emissions allowance expense allocated to cogeneration purchases. The dollar amount was estimated as the rate applied to the projected MWh of cogeneration purchases. The variance in the projected dollars was driven by the rate, as opposed to cogeneration MWh.

b. The actual SO_2 allowance rate was approximately $0.06 per ton, while the projected values were set on a per-MWh basis using the rate of $0.105 per MWh.

Polk NOx Emission Reduction

3. Please refer to page 7, lines 7-11. Please identify

a. the number of outages including the duration, and

b. the number and duration of hurricane related start-up delays.

A. a. The Polk Unit 1 gasifier had 38 outage events resulting in 106 days of downtime, including 43 days for a scheduled maintenance outage.

b. The hurricane related start-up delays refers to deferring and extending the outage timeframe. Tampa Electric expected to start a scheduled outage on September 4, 2018. Hurricane Irma's approach caused the company to pause the outage, place the unit in reserve shutdown, and wait until the inclement weather passed to continue the outage. This delay added 14 days to the overall outage schedule.

20180007-EI Staff Hearing Exhibits 00083

Separated Overfire Air (SOFA)

4. Please refer to page 7, lines 13-16. Please describe the work, if any, that was completed on the Big Bend Unit 4 SOFA project in 2017.

A. No work was needed or performed.

20180007-EI Staff Hearing Exhibits 00084

Big Bend Unit 2 Pre-Selective Catalytic Reduction

5. Please refer to page 7, lines 20-22. What type of work was performed on the secondary air dampers? Please explain why this work was not anticipated in the projections for the cost of the project.

A. Bearing replacements are not typically included in the cost projections because they are replaced on an as-needed basis, after inspections are done. All secondary air damper bearings were replaced. The normal budget for this equipment includes calibrations and inspections. Bearing replacements can usually be completed during the outage in which a routine inspection identified them as needing to be replaced, or at the next available outage.

20180007-EI Staff Hearing Exhibits 00085

Big Bend Unit 3 Pre-SCR

6. Please refer to page 7, line 24 through page 8 line 2. Please explain why the cost to replace bearings was not anticipated in the projections for the cost of the project.

A. Bearing replacements are not typically included in the cost projections because they are replaced on an as-needed basis, after inspections are done. The normal budget for this equipment includes calibrations and inspections. Bearing replacements are usually completed during the outage in which a routine inspection identified them as needing to be replaced, or at the next available outage.

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Arsenic Groundwater Study Program

7. Refer to page 9, lines 6-12. Please provide a pinpoint citation to the FDEP Site Rehabilitation Completion Order language requiring the removal and abandonment of wells and injection equipment.

A. The December 12, 2016 Conditional Site Rehabilitation Completion Order ("Completion Order") from FDEP, at page 2, item (a), lines 14 through 20, required the removal and abandonment of the wells. A copy of the Completion Order with the relevant language highlighted is attached.

20180007-EI Staff Hearing Exhibits 00087

Florida Department of Environmental Protection

Southwest District Office
13051 North Telecom Parkway
Temple Terrace, FL 33637-0926

Rick Scott
Governor

Carlos Lopez-Cantera
Lt. Governor

Jonathan P. Steverson
Secretary

December 12, 2016

Via Email Only to: tleastley@tecoenergy.com

Mr. Terry L. Eastley
Senior Environmental Specialist
Environmental, Health & Safety
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601

Subject: **Conditional Site Rehabilitation Completion Order (SRCO)**
Bayside Power Station
3602 Port Sutton Road
Hillsborough County, Tampa, Florida
FDEP Site #COM_315967/Project #336111
OGC File No. 10-2012

Dear Mr. Eastley:

The Southwest District has reviewed the Site Rehabilitation Completion Report (SRCR) with the No Further Action (NFA) with Controls Proposal, dated March 13, 2015 and subsequent SRCR addendum dated July 15, 2015, for the Tampa Electric H L Culbreath Bayside Power Station (TECO Bayside), located at 3602 Port Sutton Road, Tampa, Hillsborough County, Florida. Maps showing the location of the TECO Bayside facility and the location of the "contaminated site" (i.e., contaminant plume) for which this Order is being issued are attached as Exhibits 1 and 2 and are incorporated by reference herein.

The contamination, which resulted from former operations using coal and the discharge of coal combustion residuals, consisted of arsenic in soil and groundwater. The Conditional NFA Proposal is supported by earlier submittals, prepared pursuant to the requirements of Chapter 62-780, Florida Administrative Code (F.A.C.), which can be found in the Department's document repository at: http://depedms.dep.state.fl.us/Oculus/servlet/login.

Based on the documentation submitted with the Conditional NFA Proposal and other submitted documents, the Department has reasonable assurance that Tampa Electric Company has met the criteria in Chapter 62-780, F.A.C., including the commitments set forth in the technical submittals with respect to the recordation of institutional controls. The technical submittals indicate that acceptable Alternative Cleanup Target Levels (ACTLs) have been established for soil and groundwater contaminants remaining at the above-referenced

contaminated site, in conjunction with appropriate institutional controls. Therefore, you have satisfied the site rehabilitation requirements for the above-referenced contaminated site and are released from any further obligation to conduct site rehabilitation at the contaminated site, except as set forth below. See attached table (Exhibit 3), incorporated by reference herein, which includes information regarding the contaminants, affected media, applicable cleanup target levels, and the ACTL's established for the contaminated site that is the subject of this Order.

A Declaration of Restrictive Covenant was recorded by TECO Services, Inc. on November 11, 2016, in Official Record Book 24542, Pages 349 – 360, Public Records of Hillsborough County, Florida, and is attached and incorporated by reference as Exhibit 4.

Failure to meet the following requirement will result in the revocation of this Order:

(a) You are required to properly plug and abandon all monitoring wells, injection wells, extraction wells, and sparge wells unless these wells are otherwise required for compliance with other programs within the Department, a local ordinance, or another cleanup within 60 days of receipt of this Order. The monitoring wells must be plugged and abandoned in accordance with the requirements of Rule 62-532.500(5), F.A.C. A Well Abandonment Report shall be submitted within 30 days of well plugging;

(b) Any current or future real property owner of the above-referenced contaminated site must comply with the provisions contained within the Declaration of Restrictive Covenant (attached) recorded prior to the execution of this Order;

(c) If the current or future real property owner of the above-referenced contaminated site proposes to remove the institutional controls, the real property owner shall obtain prior written approval from the Department. The removal of the controls shall be accompanied by the immediate resumption of site rehabilitation or implementation of other approved controls, unless it is demonstrated to the Department that the criteria of subsection 62-780.680(1), F.A.C., are met.

Further, in accordance with Chapter 376.30701(4), Florida Statutes (F.S.), upon completion of site rehabilitation, additional site rehabilitation is not required unless it is demonstrated that:

(a) Fraud was committed in demonstrating site conditions or completion of site rehabilitation;

(b) New information confirms the existence of an area of previously unknown contamination which exceeds the site-specific rehabilitation levels established in accordance with Section 376.30701(2),F.S., or which otherwise poses the threat of real and substantial harm to public health, safety, or the environment;

(c) The level of risk is increased beyond the acceptable risk established under Section 376.30701(2), F.S., due to substantial changes in exposure conditions, such as a change in land use from nonresidential to residential use. Any person who changes

the land use of the site, thereby causing the level of risk to increase beyond the acceptable risk level, may be required by the department to undertake additional remediation measures to ensure that human health, public safety, and the environment are protected consistent with Section 376.30701, F.S.; or

(d) A new discharge of pollutants or hazardous substances occurs at the site subsequent to the issuance of this Order.

Legal Issues

The Department's Order shall become final unless a timely petition for an administrative hearing is filed under sections 120.569 and 120.57, F.S., within **21** days of receipt of this Order. The procedures for petitioning for a hearing are set forth below.

Persons affected by this Order have the following options:

A. If you choose to accept the Department's decision regarding this Conditional SRCO, you do not have to do anything. This Order is final and effective on the date filed with the Clerk of the Department, which is indicated on the last page of this Order.

B. If you choose to challenge the decision, you may do the following:

1. File a request for an extension of time to file a petition for hearing with the Department's Agency Clerk in the Office of General Counsel within **21** days of receipt of this Order. Such a request should be made if you wish to meet with the Department in an attempt to informally resolve any disputes without first filing a petition for hearing; or

2. File a petition for administrative hearing with the Department's Agency Clerk in the Office of General Counsel within **21** days of receipt of this Order.

Please be advised that mediation of this decision pursuant to section 120.573, F.S., is not available.

How to Request an Extension of Time to File a Petition for Hearing

For good cause shown, pursuant to Rule 62-110.106(4), F.A.C., the Department may grant a request for an extension of time to file a petition for hearing. Such a request must be filed (received) by the Agency Clerk in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida, 32399-3000, within **21** days of receipt of this Order. Petitioner, if different from the Tampa Electric Company, shall mail a copy of the request to the Tampa Electric Company at the time of filing. Timely filing a request for an extension of time tolls the time period within which a petition for administrative hearing must be made.

How to File a Petition for Administrative Hearing

A person whose substantial interests are affected by this Order may petition for an administrative hearing under sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) by the Agency Clerk in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, MS 35, Tallahassee, Florida, 32399-3000, within **21** days of receipt of this Order. Petitioner, if different from the Tampa Electric Company, shall mail a copy of the petition to the Tampa Electric Company at the time of filing. Failure to file a petition within this time period shall waive the right of anyone who may request an administrative hearing under sections 120.569 and 120.57, F.S.

Pursuant to subsection 120.569(2), F.S., and Rule 28-106.201, F.A.C., a petition for administrative hearing shall contain the following information:

a) The name, address, and telephone number of each petitioner; the name, address, and telephone number of the petitioner's representative, if any; the site owner's name and address, if different from the petitioner; the DEP facility number; and the name and address of the facility;
b) A statement of when and how each petitioner received notice of the Department's action or proposed action;
c) An explanation of how each petitioner's substantial interests are or will be affected by the Department's action or proposed action;
d) A statement of the disputed issues of material fact, or a statement that there are no disputed facts;
e) A statement of the ultimate facts alleged, including a statement of the specific facts the petitioner contends warrant reversal or modification of the Department's action or proposed action;
f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the Department's action or proposed action; and
g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the Department to take with respect to the Department's action or proposed action.

This Order is final and effective on the date filed with the Clerk of the Department, which is indicated on the last page of this Order. Timely filing a petition for administrative hearing postpones the date this Order takes effect until the Department issues either a final order pursuant to an administrative hearing or an Order Responding to Supplemental Information provided to the Department pursuant to meetings with the Department.

Judicial Review

Any party to this Order has the right to seek judicial review of it under section 120.68, F.S., by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the Agency Clerk of the Department in the 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 order is filed with the clerk of the Department (see below).

Questions

Any questions regarding the Department's review of your NFA with Controls Proposal should be directed to Mrs. Tina Madrid at the address listed above, phone number (813) 470-5762 or via email to Tina.Madrid@dep.state.fl.us. Questions regarding legal issues should be referred to the Department's Office of General Counsel at (850) 245-2242. Contact with any of the above does not constitute a petition for administrative hearing or request for an extension of time to file a petition for administrative hearing.

Sincerely,

Mary E. Yeargan

Mary E. Yeargan, P.G.
Southwest District Director
Florida Department of Environmental Protection

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52
Florida Statutes, with the designated
Department Clerk, receipt of which is
hereby acknowledged.

Samantha Black

Clerk
(or Deputy Clerk)

December 12, 2016
Date

Enclosures (Exhibits 1, 2, 3 and 4)

cc: Ms. Cathe A. Sheehan, Paralegal – TECO Services, Inc. (via email: casheehan@tecoenergy.com)
Mr. Michael N. Lodato, P.G. – Geosyntec (via email: MLodato@Geosyntec.com)
Mrs. Tina L. Madrid – FDEP (via email: tina.madrid@dep.state.fl.us)
Southwest District Clerical (via email: SWD_Clerical@dep.state.fl.us)

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (Nos. 1 - 7) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 13th day of June, 2018.

Penelope Rusk

Sworn to and subscribed before me this 13th day of June, 2018.

Cynthia R. Kyle

Notary Public State of Florida
Cynthia R Kyle
My Commission FF 197516
Expires 03/01/2019

My Commission expires _____

47

TECO's response to Staff's Second Set of Interrogatories Nos. 8-14.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 47
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope Rusk (8-10) Paul Carpinone (11-14)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	))	**DOCKET NO. 20180007-EI FILED: SEPTEMBER 17, 2018**

TAMPA ELECTRIC COMPANY'S ANSWERS TO SECOND SET OF INTERROGATORIES (NOS. 8-14) OF FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 8-14) propounded and served on August 28, 2018 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180007-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 8-14)

Number	Witness	Subject	Bates Stamped Page
8	Penelope Rusk	Please refer to TECO witness Rusk's July 25, 2018 testimony page 10, lines 3-7. Will the decrease in maintenance cost this year cause an increase in the maintenance cost for the projected year 2019?	1
9	Penelope Rusk	Please refer to TECO witness Rusk's July 25, 2018 testimony page 12, lines 8-12. What is "Low Emitting Electric Generating Unit" status and how does a unit achieve it?	2
10	Penelope Rusk	Please refer to TECO witness Rusk's July 25, 2018 testimony page 12, lines 14-18. How did the delay in completing the Big Bend ELG Study project cause a project variance greater than projected?	3
11	Paul Carpinone	Please refer to TECO witness Carpinone's July 25, 2018 testimony page 5, line 22 through page 6, line 1. When is the Big Bend Station NPDES permit expected to be finalized?	4
12	Paul Carpinone	Please refer to TECO witness Carpinone's July 25, 2018 testimony page 6, lines 1-13. What is the estimated timeline of the Big Bend Unit 1 Modernization project? a. Will the addition of the impingement mortality compliance equipment increase the time to complete the Modernization project? b. If the answer to 12.a. is "yes," by how much?	5
13	Paul Carpinone	Please refer to TECO witness Carpinone's July 25, 2018 testimony page 7, line 25 through page 8, line 6. Please identify any other potential solutions that were investigated by the engineering firm, and the reason(s) such solutions were rejected.	6
14	Paul Carpinone	Please refer to TECO witness Carpinone's July 25, 2018 testimony page 16, line 12 through page 17, line 11. Please provide a table with a breakdown of deep injection well capital costs by year for the period 2018 to 2021 for the following scenarios: a. No water softening. b. Blended with county treated effluent. c. Full Softening.	7

Penelope Rusk
Manager, Rates

Paul Carpinone
Director, Environmental

Tampa Electric Company
702 N. Franklin Street
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O&M Project Variances

8. Please refer to TECO witness Rusk's July 25, 2018 testimony page 10, lines 3-7. Will the decrease in maintenance cost this year cause an increase in the maintenance cost for the projected year 2019?

A. No. The reduction in the 2018 PM Minimization & Monitoring project maintenance costs is based on the expectation of a reduced need for maintenance work overall, not a timing difference, and this is due to greater operations on natural gas and less on coal, compared to the original projection. This change is expected to result in less wear and tear on the equipment and therefore less maintenance costs in 2018. Costs are expected to be approximately level in 2019 since the amount of coal generation is not expected to increase in 2019.

Mercury Air Toxics Standards.

9. Please refer to TECO witness Rusk's July 25, 2018 testimony page 12, lines 8-12. What is "Low Emitting Electric Generating Unit" status and how does a unit achieve it?

A. An electric generating unit (EGU) may qualify for Low Emitting EGU (LEE) status if a facility collects performance test data that demonstrates compliance with emission limits that are lower than the allowable limits specified by the MATS rule. More specifically, these compliance standards are as follows.

1. Performance test emissions results less than 50 percent of the applicable emissions limits specified in the MATS rule for all required testing for 3 consecutive years.
2. For mercury emissions, either average emissions of less than 10 percent of the applicable mercury emissions limit in or potential mercury mass emissions of 29 or fewer pounds per year and compliance with the applicable mercury emission limit.

Units that have achieved LEE status may have less frequent testing requirements as long as LEE status is maintained.

Big Bend ELG Rule Study

10. Please refer to TECO witness Rusk's July 25, 2018 testimony page 12, lines 14-18. How did the delay in completing the Big Bend ELG Study project cause a project variance greater than projected?

A. For the Big Bend ELG Rule Study program, all costs were expected to be incurred by the end of 2017; however, as the timing of the study completion changed, the delay resulted in a 2018 variance simply because 0 costs were originally projected for 2018. Overall, total project costs decreased. See the following table for a demonstration of how the cost estimates and timing changed since the petition was filed.

Big Bend ELG Rule Study Program Expenses ($000)

		2016	2017	2018	Total
Petition	(1)	100	300	0	400
Updates Filed in 2016	(2)	303	50	0	353
Updates Filed in 2017	(3)	242	197	0	439
Updates Filed in 2018	(4)	242	19	54	315
Actual *	(4)	242	19	54	315

(1) Submitted February 2, 2016 in Docket No. 20160023-EI

(2) 2016 Act-Est, 2017 Projection

(3) 2016 Final True-Up, 2017 Act-Est, 2018 Projection

(4) 2016 Final True-Up, 2017 Final True-Up, 2018 Act-Est

* Though the study was completed in 2018, if regulatory authorities determine that the study scope must be expanded before the compliance program permit is issued, then additional costs may need to be incurred in the future.

Big Bend NPDES

11. Please refer to TECO witness Carpinone's July 25, 2018 testimony page 5, line 22 through page 6, line 1. When is the Big Bend Station NPDES permit expected to be finalized?

A. The NPDES permit is still under review. To date, Tampa Electric has provided all of the requested information to FDEP. FDEP has not yet provided an estimated completion date.

Impingement Mortality Compliance

12. Please refer to TECO witness Carpinone's July 25, 2018 testimony page 6, lines 1-13. What is the estimated timeline of the Big Bend Unit 1 Modernization project?

a. Will the addition of the impingement mortality compliance equipment increase the time to complete the Modernization project?

b. If the answer to 12.a. is "yes," by how much?

A. Construction related to the Big Bend Unit 1 Modernization project is estimated to begin in June 2019 with an in-service date projected to be January 2023. Regarding the Big Bend Impingement Mortality ("IM") project, the design for IM compliance equipment has already started and is being performed in parallel with the design of the modernization project. The current schedule shows construction beginning in December 2021, IM compliance equipment installation beginning in February 2022 and IM compliance equipment installation completion in July 2022 to support startup of the unit in combined cycle.

a. No.

b. NA

Impingement Mortality Compliance.

13. Please refer to TECO witness Carpinone's July 25, 2018 testimony page 7, line 25 through page 8, line 6. Please identify any other potential solutions that were investigated by the engineering firm, and the reason(s) such solutions were rejected.

A. Tampa Electric reviewed all of the approaches provided for the rule for feasibility and/or applicability. The potential solutions are listed below, along with the reasons for each option's selection or rejection.

a. Operate a closed-cycle recirculating system as defined at § 125.92 – infeasible and not cost effective
b. Operate a cooling water intake structure that has a maximum through-screen design intake velocity of 0.5 fps – infeasible and not cost effective
c. Operate a cooling water intake structure that has a maximum through-screen intake velocity of 0.5 fps – not applicable
d. Operate an offshore velocity cap as defined at § 125.92 that is installed before October 14, 2014 – not applicable
e. Operate a modified traveling screen (selected option) – feasible, applicable and most cost effective
f. Operate any other combination of technologies, management practices and operational measures that the Director determines is the best technology available for impingement reduction – untested; potential delays in permitting
g. Achieve the specified impingement mortality performance standard – costly ongoing performance monitoring; potential delays in permitting

Effluent Limitations Compliance

14. Please refer to TECO witness Carpinone's July 25, 2018 testimony page 16, line 12 through page 17, line 11. Please provide a table with a breakdown of deep injection well capital costs by year for the period 2018 to 2021 for the following scenarios:

a. No water softening.

b. Blended with county treated effluent.

c. Full Softening.

A. As described in witness Carpinone's July 25, 2018 testimony, there are three options that the company is considering for pretreatment of effluent discharge which will be determined after the FDEP review and test well results. The options range in cost from an estimated $18 million if no water softening is required and the company is permitted to allow blending wastewater with county treated effluent, to approximately $21 million if 30 percent softening is required, and up to $26 million if full softening is required. A table showing the estimated costs associated with the 30 percent softening option is shown in witness Carpinone's testimony. There is no option that considers "no water softening" without blending, as it is expected that some treatment of the water will be required by FDEP.

The following tables show the projected annual costs of the other two options, Deep Injection Wells with No water Softening and Blended with County Treated Effluent, and Deep Injection Wells with Full Water Softening.

20180007-EI Staff Hearing Exhibits 00104

Deep Injection Wells with No Water Softening and Blended with County Treated Effluent

	2018 ($000)	2019 ($000)	2020 ($000)	2021 ($000)	Total ($000)
Capital					
Permitting and Pre-Construction Engineering Design	150	250	700	-	1,100
Construction Engineering	-		1,800	400	2,200
Well Construction (2 wells)	-		5,000	3,000	8,000
Water Treatment (No Softening and Blended with Effluent)	-		4,700	2,000	6,700
Total	150	250	12,200	5,400	18,000

Deep Injection Wells with Full Water Softening

	2018 ($000)	2019 ($000)	2020 ($000)	2021 ($000)	Total ($000)
Capital					
Permitting and Pre-Construction Engineering Design	150	250	700	-	1,100
Construction Engineering	-		1,800	400	2,200
Well Construction (2 wells)	-		5,000	3,000	8,000
Water Treatment (Full Softening)	-		7,700	7,000	14,700
Total	150	250	15,200	10,400	26,000

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (Nos. 8-14) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 14th day of September, 2018.

Penelope Rusk

Sworn to and subscribed before me this 14th day of September, 2018.

Sana Boric

Notary Public State of Florida
Sana Boric
My Commission GG 020235
Expires 08/10/2020

My Commission expires _____

48

TECO's response to Staff's Third Set of Interrogatories No. 15-16.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 48
PARTY: STAFF – (DIRECT)
DESCRIPTION: Paul Carpinone

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	))	DOCKET NO. 20180007-EI FILED: OCTOBER 5, 2018

TAMPA ELECTRIC COMPANY'S

ANSWERS TO THIRD SET OF INTERROGATORIES (NOS. 15-16)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 15-16) propounded and served on September 25, 2018 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180007-EI
INDEX TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 15-16)

Number	Witness	Subject	Bates Stamped Page
15	Paul Carpinone	Please refer to TECO witness Carpinone's direct testimony from August 24, 2018, page 5, lines 12-17. a. Please identify and describe the costs associated with the $60,000 in O&M expenses for the NOx reduction equipment. b. How often is maintenance performed on the equipment?	1
16	Paul Carpinone	Please refer to TECO witness Carpinone's direct testimony from August 24, 2018, page 7, lines 2-6. a. Please identify and describe the causes for the differences in O&M expenses for each Big Bend Unit, 1-4. b. What causes the significant increase in the projected O&M expenses for Big Bend Unit 4 SCR? c. Please identify the cost of ammonia purchases for each Big Bend Unit.	2

Paul Carpinone
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NOx Emission Reduction.

15. Please refer to TECO witness Carpinone's direct testimony from August 24, 2018, page 5, lines 12-17.

a. Please identify and describe the costs associated with the $60,000 in O&M expenses for the NOx reduction equipment.

b. How often is maintenance performed on the equipment?

A. a. The projected O&M expenses for the NOx reduction equipment are for materials and contractors to complete general maintenance of the combustion systems to balance combustion and NOx emissions as well as equipment testing and operational tuning.

b. Maintenance needs are identified during routine inspections and testing and completed on an as-needed basis.

Pre-Selective Catalyctic Reduction Projects (SCR).

16. Please refer to TECO witness Carpinone's direct testimony from August 24, 2018, page 7, lines 2-6.

a. Please identify and describe the causes for the differences in O&M expenses for each Big Bend Unit, 1-4.

b. What causes the significant increase in the projected O&M expenses for Big Bend Unit 4 SCR?

c. Please identify the cost of ammonia purchases for each Big Bend Unit.

A. a. O&M expenses are estimated based on the projected capacity factor and fuel usage of each unit. Units with higher natural gas usage result in lower uncontrolled NOx emissions and therefore lower the ammonia usage.

b. Big Bend Unit 4 has a higher projected capacity factor and greater projected coal usage than Big Bend Units 1-3 during 2019.

c. The projected cost of ammonia purchases for each Big Bend Unit are as follows.

Unit 1: $143,150
Unit 2: $234,500
Unit 3: $288,225
Unit 4: $1,434,125

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared, Penelope Rusk who deposed and said that she is Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Third Set of Interrogatories, (Nos. 15-16) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 4th day of October, 2018.

Penelope Rusk

Sworn to and subscribed before me this 4th day of October, 2018.

Sana Boric

Notary Public State of Florida
Sana Boric
My Commission GG 020235
Expires 06/10/2020

My Commission expires _____

EXHIBIT NO. 49

DOCKET NO: 20180007

WITNESS: SOLE

PARTY: FPL

DESCRIPTION: Section 366.8255, Fla. Stat.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 49
PARTY: OPC
DESCRIPTION: ECR Statute

PROFFERED BY: Office of Public Counsel

366.8255 Environmental cost recovery.—

(1) As used in this section, the term:

(a) "Electric utility" or "utility" means any investor-owned electric utility that owns, maintains, or operates an electric generation, transmission, or distribution system within the State of Florida and that is regulated under this chapter.

(b) "Commission" means the Florida Public Service Commission.

(c) "Environmental laws or regulations" includes all federal, state, or local statutes, administrative regulations, orders, ordinances, resolutions, or other requirements that apply to electric utilities and are designed to protect the environment.

(d) "Environmental compliance costs" includes all costs or expenses incurred by an electric utility in complying with environmental laws or regulations, including, but not limited to:

1. Inservice capital investments, including the electric utility's last authorized rate of return on equity thereon.
2. Operation and maintenance expenses.
3. Fuel procurement costs.
4. Purchased power costs.
5. Emission allowance costs.
6. Direct taxes on environmental equipment.
7. Costs or expenses prudently incurred by an electric utility pursuant to an agreement entered into on or after the effective date of this act and prior to October 1, 2002, between the electric utility and the Florida Department of Environmental Protection or the United States Environmental Protection Agency for the exclusive purpose of ensuring compliance with ozone ambient air quality standards by an electrical generating facility owned by the electric utility.
8. Costs or expenses prudently incurred for scientific research and geological assessments of carbon capture and storage conducted in this state for the purpose of reducing an electric utility's greenhouse gas emissions when such costs or expenses are incurred in joint research projects with Florida state government agencies and Florida state universities.

(2) An electric utility may submit to the commission a petition describing the utility's proposed environmental compliance activities and projected environmental compliance costs in addition to any Clean Air Act compliance activities and costs shown in a utility's filing under s. 366.825. If approved, the commission shall allow recovery of the utility's prudently incurred environmental compliance costs, including the costs incurred in compliance with the Clean Air Act, and any amendments thereto or any change in the application or enforcement thereof, through an environmental compliance cost-recovery factor that is separate and apart from the utility's base rates. An adjustment for the level of costs currently being recovered through base rates or other rate-adjustment clauses must be included in the filing.

(3) The environmental compliance cost-recovery factor must be set periodically, but at least annually, based on projections of the utility's environmental compliance costs during the forthcoming recovery period, and must be adjusted for variations in line losses. The environmental compliance cost-recovery factor must provide for periodic true-up of the utility's actual environmental compliance costs with the projections on which past factors have been set, and must further require that any refund or collection made as part of the true-up process include interest.

(4) Environmental compliance costs recovered through the environmental cost-recovery factor shall be allocated to the customer classes using the criteria set out in s. 366.06(1), taking into account the manner in which similar types of investment or expense were allocated in the company's last rate case.

(5) Recovery of environmental compliance costs under this section does not preclude inclusion of such costs in base rates in subsequent rate proceedings, if that inclusion is necessary and appropriate; however, any costs recovered in base rates may not also be recovered in the environmental cost-recovery clause.

History.—s. 7, ch. 93-35; s. 1, ch. 2002-276; s. 40, ch. 2008-227; s. 2, ch. 2012-89.

366.8260 Storm-recovery financing.—

(1) DEFINITIONS.—As used in this section, the term:

(a) "Ancillary agreement" means any bond, insurance policy, letter of credit, reserve account, surety bond, swap arrangement, hedging arrangement, liquidity or credit support arrangement, or other financial arrangement entered into in connection with the issuance of storm-recovery bonds.

(b) "Assignee" means any entity, including, but not limited to, a corporation, limited liability company, partnership or limited partnership, public authority, trust, financing entity, or other legally recognized entity to which an electric utility assigns, sells, or transfers, other than as security, all or a portion of its interest in or right to storm-recovery property. The term also includes any entity to which an assignee assigns, sells, or transfers, other than as security, its interest in or right to storm-recovery property.

(c) "Commission" means the Florida Public Service Commission.

(d) "Electric utility" or "utility" has the same meaning as that provided in s. 366.8255.

(e) "Financing costs" means:

1. Interest and acquisition, defeasance, or redemption premiums that are payable on storm-recovery bonds;
2. Any payment required under an ancillary agreement and any amount required to fund or replenish a reserve account or other accounts established under the terms of any indenture, ancillary agreement, or other financing documents pertaining to storm-recovery bonds;
3. Any other cost related to issuing, supporting, repaying, and servicing storm-recovery bonds, including, but not limited to, servicing fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, administrative fees, placement and underwriting fees, capitalized interest, rating agency fees, stock exchange listing and compliance fees, and filing fees, including costs related to obtaining the financing order;

EXHIBIT NO 50

DOCKET NO: 20180007

WITNESS: SOLE

PARTY: FPL

DESCRIPTION: February 12, 2018 and March 5, 2018 FPL Petitions

PROFFERED BY: Office of Public Counsel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 50
PARTY: OPC
DESCRIPTION: 02.12.18 amd 3.5.18 FPL Petitions

FILED 2/12/2018
DOCUMENT NO. 01138-2018
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No: 20180007-EI Filed: February 12, 2018

PETITION FOR APPROVAL OF MODIFICATION TO MANATEE TEMPORARY HEATING SYSTEM PROJECT

Florida Power & Light Company ("FPL") hereby petitions the Florida Public Service Commission ("Commission") for approval of a modification to its approved Manatee Temporary Heating System ("MTHS") Project such that prudent costs incurred after the date of this Petition for the modification may be recovered as "environmental compliance costs" through the Environmental Cost Recovery Clause ("ECRC"). In support of this Petition, FPL states as follows:

1. Section 366.8255, Florida Statutes, authorizes the Commission to review and approve environmental compliance projects, and modifications to such projects, for which prudently incurred environmental compliance costs may be recovered through the ECRC.

2. FPL is requesting to modify its existing, approved MTHS Project to include an MTHS at FPL's Fort Myers Plant site ("PFM"). Previously, this Commission has approved the MTHS Project to allow recovery of costs incurred to meet permit requirements for providing warm water manatee refuges at FPL's Cape Canaveral, Riviera Beach, Port Everglades and Fort Lauderdale plants while they were shut down for modernization projects. As described in further detail below, the inclusion of an MTHS for PFM is being undertaken in order to comply with a similar permit requirement, during periods when PFM is shut down for extended outages or because it is not being economically dispatched.

3. PFM was repowered in 2003 with what was highly efficient combined cycle technology for the time. As part of the Manatee Protection Plan that was approved on July 12, 1999, and is implemented via PFM's NPDES permit, FPL is obligated to maintain a warm water manatee refuge if the water temperature at the PFM's cooling water discharge falls below 61 degrees Fahrenheit. PFM's current NPDES Permit No. CFL0001490 was issued by the Florida Department of Environmental Protection ("FDEP") effective January 20, 2016. This permit requirement is substantially the same as the permit requirements at the Cape Canaveral, Riviera Beach, Port Everglades and Fort Lauderdale plants, for which the Commission has previously authorized FPL to include an MTHS within the approved MTHS Project.

4. Until recently, FPL has not needed to have an MTHS at PFM because the plant routinely operated during the manatee heating season and thus the plant's regular cooling water discharges provided a sufficient and consistent supply of warm water. For the reasons described below, however, FPL cannot continue to rely solely on the plant's regular cooling water discharges to meet the permit requirement for a warm water manatee refuge.

5. Over the past two decades, FPL has embarked on a concerted program of upgrading its fossil power plant fleet, constructing state-of-the-art combined cycle units at its Turkey Point, Martin, Manatee, West County, Cape Canaveral, Riviera Beach and Port Everglades plant sites, with another such unit planned to go into service in 2019 at the Okeechobee plant site. With each successive generation of combined cycle technology, the efficiency has continued to improve, resulting in $9.3 billion in fuel savings for customers and over 120 million tons of carbon dioxide avoided. The addition of these highly efficient combined cycle units has had two consequences for PFM that are now requiring the addition of an MTHS at the site.

6. First, combined cycle units need significant routine maintenance. Until now, FPL has been able to schedule the maintenance for PFM outside of the manatee season (November 15 – March 31) so that it would be able to rely on the plant's normal cooling water discharge to provide a warm water manatee refuge without the need for an MTHS. The upgrades at other plant sites discussed above have resulted in both a significant increase in the number of combined cycle units requiring routine maintenance and a significant decrease in the number of smaller units with individual steam turbines that can remain in operation to provide warm water for manatees. For example, prior to 2013, the Cape Canaveral plant consisted of two individual steam units; now the plant consists of three combustion turbines with heat recovery steam generators that provide steam to a single steam turbine. When the Cape Canaveral plant is taken out of service today, the single steam turbine is idled and thus no cooling water discharge is available to provide warm water for manatees.

7. The size of FPL's combined cycle fleet and the reduction in the number of small, single units that can be taken out of service separately for maintenance outages has now reached the point that FPL can no longer ensure that the PFM outages are sequenced outside of manatee season. In fact, FPL will be commencing a maintenance outage at PFM on March 5, 2018, which is within the manatee season. FPL needs to be prepared for the possibility of cold weather during that outage and future outages that would require an MTHS to meet the permit requirement for a warm water manatee refuge.

8. Second, improvements in the efficiency of FPL's fossil fuel fleet since the time that PFM was repowered have pushed PFM down the dispatch stack to the point that FPL can no longer be confident that it will be dispatched regularly and for sustained periods during winter months. When PFM was first repowered, it was one of the most efficient and economical units

in FPL's fleet, and as such, it would be dispatched routinely even during periods of relatively low winter-time load. Now, however, the more recent combined cycle units are more efficient and are dispatched before PFM, with the result that there may be extended periods during manatee season when PFM would not be dispatched to meet load and thus would not be producing a cooling water discharge that could maintain the necessary warm water manatee refuge. While it would be possible to dispatch PFM out of dispatch in order to provide warm water, the substantial fuel and other operating and maintenance expenses incurred to do so means that it would not be as economic as installing an MTHS.

9. In order for FPL to provide warm water during the March 2018 outage, a temporary diesel-burning MTHS is being rented and temporarily installed at the site. To provide warm water for future outages during manatee season, FPL is purchasing and installing an electric MTHS at the site. This electric MTHS will be similar to what was installed at the Cape Canaveral Clean Energy Center.

10. Following the filing of this petition, FPL estimates that it will incur $250,000 in O&M expenses for the temporary diesel-burning system, consisting of rental payments and fuel. The total estimated capital cost for the electric MTHS is $5 million. FPL's total annual O&M estimate for the electric MTHS is $30,000. This modification satisfies the three-part test for ECRC eligibility set forth in Order No. PSC-94-0044-FOF-EI.[1]

11. FPL asks that the Commission consider this Petition at its regular hearing in this docket, which FPL understands will be scheduled in the Fall of 2018. FPL intends to file

1 Order No. PSC-94-0044-FOF-EI states:
Upon petition, we shall allow the recovery of costs associated with an environmental compliance activity through the environmental cost recovery factor if:
1. such costs were prudently incurred after April 13, 1993;
2. the activity is legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and,
3. such costs are not recovered through some other cost recovery mechanism or through base rates.

supporting testimony and exhibits providing additional detail on the PFM MTHS in conjunction with its 2017 Final True-Up filing in this docket, which FPL expects to be due on or about April 1, 2018. This will provide ample time for the Commission Staff and all parties to review and conduct discovery regarding the proposed project modification before the Fall 2018 hearing.

WHEREFORE, FPL respectfully requests that the Commission approve modification of the MTHS Project to include the PFM MTHS as an "environmental compliance activity," such that prudent costs incurred for the PFM MTHS after the date of this petition may be recovered through the ECRC.

Respectfully submitted,

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By: *s/ John T. Butler*
John T. Butler
Florida Bar No. 283479

CERTIFICATE OF SERVICE
Docket No. 20180007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service on this 12th day of February 2018 to the following:

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FILED 3/5/2018
DOCUMENT NO. 02120-2018
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No: 20180007-EI Filed: March 5, 2018

PETITION FOR APPROVAL OF MODIFICATION TO NATIONAL POLLUTION DISCHARGE ELIMINATION SYSTEM PERMIT RENEWAL REQUIREMENT PROJECT

Florida Power & Light Company ("FPL") hereby petitions the Florida Public Service Commission ("Commission") for approval of a modification to its approved National Pollution Discharge Elimination System ("NPDES") Permit Renewal Requirement Project such that prudent costs incurred after the date of this Petition for the modification may be recovered as environmental compliance costs through the Environmental Cost Recovery Clause ("ECRC"). In support of this Petition, FPL states as follows:

Introduction

1. Section 366.8255, Florida Statutes, authorizes the Commission to review and approve environmental compliance projects, and modifications to such projects, for which prudently incurred environmental compliance costs may be recovered through the ECRC.

2. In 2011, this Commission approved the NPDES Permit Renewal Requirement Project to allow recovery of costs incurred to meet NPDES permit requirements for all of FPL's Florida plants. FPL requests a modification to the NPDES Permit Renewal Requirement Project to allow recovery of costs incurred to meet anticipated NPDES permit conditions and compliance schedules to be imposed on Plant Scherer by the Environmental Protection Division ("EPD") of Georgia's Department of Natural Resources.

3. FPL and JEA jointly own Unit 4 at Plant Scherer, located in Georgia. Georgia Power Company ("Georgia Power") serves as the operator for Unit 4, as it does for the other

three Plant Scherer generating units. Plant Scherer must renew its NPDES permit, and Georgia Power is actively pursuing the renewal. As described in further detail below, testing has revealed that Plant Scherer copper discharges into the Ocmulgee River have a reasonable potential to exceed Georgia's prescribed water quality standards. Georgia Power has determined that the principal source of copper in the discharged water is from copper condenser tubes at each of the four Plant Scherer generating units. Corrosion and erosion of the condenser tubing has resulted in the copper being entrained in cooling tower packing material, which then acts as a secondary source of copper. Accordingly, Georgia Power has embarked on a program to replace the condenser tubes and cooling tower packing material (the latter known as "repacking") at each unit in order to remove these sources of copper. The condenser tubes have already been replaced at Unit 4 as part of normal maintenance actions, and as such, the cost of that replacement is not the subject of this requested project modification. However, the Unit 4 cooling tower packing material has not yet been replaced, and Georgia Power intends to perform the repacking during its next regularly scheduled maintenance outage that is scheduled to commence on March 8, 2018.

4. As demonstrated below, FPL's requested modification to the NPDES Permit Renewal Requirement Project satisfies the three-part test for ECRC eligibility set forth in Order No. PSC-94-0044-FOF-EI.[1]

[1] Order No. PSC-94-0044-FOF-EI states:
Upon petition, we shall allow the recovery of costs associated with an environmental compliance activity through the environmental cost recovery factor if:
1. such costs were prudently incurred after April 13, 1993;
2. the activity is legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and,
3. such costs are not recovered through some other cost recovery mechanism or through base rates.

NPDES Program

5. The federal Clean Water Act requires all point source discharges to navigable waters from industrial facilities to obtain permits under the NPDES program. 33 U.S.C. § 1342 (2017). This applies to all of FPL's power plants.

6. In 2011, the Commission approved FPL's NPDES Permit Renewal Requirement Project, which authorized cost recovery for activities required to satisfy whole effluent toxicity limits and the Storm Water Pollution Prevention Plan, which were requirements established by the Florida Department of Environmental Protection ("DEP") that were to be effective when FPL's Florida power plants renewed their NPDES permits. Order No. PSC-11-0553-FOF-EI. In 2012 the Commission approved a modification to the NPDES Permit Renewal Requirement Project, authorizing recovery of costs associated with additional permit requirements that were imposed by the Florida DEP for Plant St. Lucie. Order No. PSC-12-0613-FOF-EI.

7. With one exception, all of FPL's power plants are located in Florida and therefore already are part of the NPDES Permit Renewal Requirement Project. The one exception is FPL's ownership interest in Plant Scherer Unit 4 located in Georgia.

8. The Environmental Protection Agency has delegated authority to issue NPDES permits in the state of Georgia to the EPD. Plant Scherer's NPDES permit was issued by the EPD in 2002, was administratively extended in 2006, and is currently in effect but must be renewed. Wastewater discharges from Plant Scherer cannot cause a water body to exceed Georgia's Water Quality Standards ("WQS"). Georgia's long-term ("chronic") WQS standard for copper in the Ocmulgee River is 5 parts per billion ("ppb"), at the terminus of a mixing zone.

9. On January 30, 2018, Plant Scherer submitted an updated NPDES permit renewal application. Included in the application is a table showing the results of recent water quality testing for various outfalls from the Plant. One of the test results showed that the copper

concentration in effluent discharged to the river from cooling tower blowdown and other wastewater has a potential to cause the Plant to exceed the Georgia WQS. Based on the EPD's permitting procedures, FPL and Georgia Power anticipate that EPD will include in the facility's renewed permit a new condition that requires additional monitoring for copper in the effluent, an effluent limit for copper to ensure that the effluent does not cause an exceedance of the Georgia WQS, and a compliance schedule enabling the Plant to meet this limit.

Georgia Power's Plan To Reduce Copper Levels

10. Georgia Power analyzed the source of Plant Scherer's copper discharge and evaluated options for reducing copper concentrations in the discharge. Based on that analysis, Georgia Power determined that the elevated copper levels in the effluent were attributable to two sources: (1) corrosion and erosion of the Plant's copper condenser tubes, and (2) concentration of copper in the cooling tower packing, where copper from the condenser tubes has become entrained. Packing is a medium used in cooling towers to increase the surface area over which cooling water is exposed to air in the tower. Increased surface area allows for maximum contact between the air and the water, which allows for greater heat transfer and lower temperature cooling water being returned to the condenser, resulting in efficient operation of the unit.

11. Georgia Power considered options to attain the necessary reduction in copper discharge from Plant Scherer. Georgia Power selected the most cost-effective, long-term solution, which entails replacing the copper condenser tubes with titanium tubes and replacing the existing packing in the cooling towers with new packing material.

12. Georgia Power already has completed the replacement of the copper condenser tubes in Unit 4 and one additional unit. FPL does not seek to include the costs it incurred for the Unit 4 copper condenser tube replacement as part of this request because (unlike the repacking) replacement of those tubes was needed as part of regular maintenance. Georgia Power plans to

proceed with retubing the condensers and repacking the cooling towers for all four units, in order to ensure that the discharge is protective of the Georgia WQS and remains in compliance with the permit. On February 28, 2018, Georgia Power sent each of the co-owners of the Plant Scherer units, including FPL, a letter outlining its plans for this work.

13. To maximize efficiency, Georgia Power plans to complete the remaining tube replacements and the repacking for all four Plant Scherer units during the next planned outage for each unit. The next outage for Unit 4 is scheduled to begin March 8, 2018. Accordingly, FPL seeks to modify the NPDES Permit Renewal Requirement Project to include repacking and associated monitoring at Scherer Unit 4 because it is a cost-effective approach to meet the reduced copper concentration level reasonably anticipated to be required by the renewed NPDES permit. Indeed, the satisfaction of water quality standards is an issue of great importance to the EPD, Georgia Power, FPL, and JEA. It is therefore reasonable to move forward with these steps now to provide EPD assurance that Plant Scherer's discharge will be protective of the WQS under its renewed NPDES permit.

14. The total estimated cost for repacking at Plant Scherer Unit 4 is $9 million. Because the NPDES permit renewal process is still in an early stage, FPL is not seeking current ECRC recovery of the Unit 4 repacking costs. Rather, FPL requests approval to recover those costs as follows:

a. During the period between submission of the NPDES permit application and the EPD's issuance of the NPDES permit, FPL will exclude the costs incurred for repacking at Plant Scherer Unit 4 from the ECRC-recoverable accounts and instead will record those costs in base plant-in-service accounts and include the undepreciated balance in rate base. Any associated O&M

expenses and depreciation expenses would be recorded as base rate recoverable expenses.

b. If, as anticipated, the renewed NPDES permit for Plant Scherer includes a condition that requires a reduction in copper concentration, FPL will transfer the remaining net book value of all reasonable and prudent capital costs from the base plant-in-service accounts to ECRC-recoverable accounts. In addition, future reasonable and prudent capital and O&M expenses associated with the Unit 4 repacking activity will be recorded in ECRC-recoverable accounts.

15. FPL petitions at this time for approval to add Unit 4 repacking and associated monitoring at Plant Scherer to its currently approved NPDES Permit Renewal Requirement Project because FPL must begin making expenditures immediately in order to complete the repacking during the 2018 outage for Unit 4. FPL asks that the Commission consider this Petition at its regular hearing in this docket, which FPL understands will be scheduled in the fall of 2018. FPL intends to file supporting testimony and exhibits providing additional detail on the Plant Scherer repacking activity in conjunction with its 2017 Final True-Up filing in this docket, which FPL will file April 2, 2018. This will provide ample time for the Commission Staff and all parties to review and conduct discovery regarding the proposed project modification before the November 2018 hearing.

WHEREFORE, FPL respectfully requests that the Commission approve a modification of the NPDES Permit Renewal Requirement Project to include the repacking and associated

monitoring at Plant Scherer Unit 4 as an environmental compliance activity, such that prudent costs incurred for repacking after the date of this petition may be recovered through the ECRC.

Respectfully submitted,

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By: *s/ Maria Jose Moncada*
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CERTIFICATE OF SERVICE
Docket No. 20180007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service on this 5th day of March 2018 to the following:

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EXHIBIT NO. 51

DOCKET NO: 20180007

WITNESS: SOLE

PARTY: FPL

DESCRIPTION: Order No. PSC-11-0553-FOF-EI

PROFFERED BY: Office of Public Counsel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 51
PARTY: OPC
DESCRIPTION: PSC-11-0553-FOF-EI

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 110007-EI ORDER NO. PSC-11-0553-FOF-EI ISSUED: December 7, 2011

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
LISA POLAK EDGAR
RONALD A. BRISÉ
EDUARDO E. BALBIS
JULIE I. BROWN

APPEARANCES:

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On behalf of Tampa Electric Company (TECO)

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On behalf of Gulf Power Company (GULF)

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DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

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Advisor to the Florida Public Service Commission.

FINAL ORDER APPROVING PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR ENVIRONMENTAL COST RECOVERY FACTORS

BY THE COMMISSION;

I. BACKGROUND

As part of our ongoing environmental cost recovery proceedings, a hearing was held on November 1 and 2, 2011, in this docket. At the hearing, the parties addressed the issues set out in Order No. PSC-11-0505-PHO-EI, the Prehearing Order. We have authority pursuant to Section 366.8255, Florida Statutes (F.S.).

II. STIPULATED GENERIC COST RECOVERY ISSUES[1]

A. We approve as reasonable the following final environmental cost recovery true-up amounts for the period ending December 31, 2010:

FPL: $5,036,426 over-recovery.

PEF: $6,232,839 over-recovery.

TECO: $2,616,798 under-recovery.

GULF: $861,325 over-recovery.

[1] In the case of PEF, the amounts set forth in this Section II reflect fall-out calculations based on our determination of the costs associated with purchases of replacement power due to the Crystal River Unit 3 extended outage, addressed at Section IV of this Order, and related stipulations.

B. We approve as reasonable the following estimated environmental cost recovery true-up amounts for the period January 2011 through December 2011:

FPL: $8,708,673 over-recovery.

PEF: $2,552,337 over-recovery.

TECO: $464,090 under-recovery.

GULF: $14,380,513 over-recovery.

C. We approve as reasonable the following projected environmental cost recovery amounts for the period January 2012 through December 2012:

FPL: $188,014,660.

PEF: $207,302,671.

TECO: $84,067,581.

GULF: $165,075,432.

D. We approve as reasonable the following environmental cost recovery amounts, including true-up amounts, for the period January 2012 through December 2012:

FPL: $174,395,035.

PEF: $198,660,428.

TECO: $87,211,216.

GULF: $149,941,474

E. We approve as reasonable that the depreciation rates used to calculate the depreciation expense should be the rates that are in effect during the period the allowed capital investment is in service.

F. We approve as reasonable the following jurisdictional separation factors for the projected period January 2012 through December 20121:

FPL:	Retail Energy Jurisdictional Factor	98.08128%
	Retail CP Demand Jurisdictional Factor	98.01395%
	Retail GCP Demand Jurisdictional Factor	100.00000%

PEF: The jurisdictional energy separation factor is calculated for each month based on retail kWh sales as a percentage of projected total system kWh sales.
Production Base – 92.792%
Production Intermediate – 72.541%
Production Peaking – 91.972%
Transmission – 69.516%
Distribution Primary– 99.624%
A&G – 92.374%

TECO: The demand jurisdictional separation factor is 99.58152%. The energy jurisdictional separation factors are calculated for each month based on projected retail kWh sales as a percentage of projected total system kWh sales.

GULF: The demand jurisdictional separation factor is 96.44582%. Energy jurisdictional separation factors are calculated each month based on retail KWH sales as a percentage of projected total territorial KWH sales.

G. We approve as reasonable the following environmental cost recovery factors for the period January 2011 through December 2011 for each rate group:

FPL:

Rate Class	Environmental Recovery Factor ($/kWh)
RS1/RST1	.00192
GS1/GST1	.00154
GSD1/GSDT1/HLFT1 (21-499 kW)	.00150
OS2	.00096
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	.00151
GSLD2/GSLDT2/CS2/CST2/HLFT3 (2,000 kW+)	.00129
GSLD3/GSLDT3/CS3/CST3	.00125
ISST1D	.00098
ISST1T	.00171
SST1T	.00171
SST1D1/SST1D2/SST1D3	.00098
CILC D/CILC G	.00118
CILC T	.00113
MET	.00154
OL1/SL1/PL1	.00039
SL2/GSCU1	.00125

PEF:

Rate Class	ECRC Factors
Residential	0.545 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.539 cents/kWh
@ Primary Voltage	0.534 cents/kWh
@ Transmission Voltage	0.528 cents/kWh
General Service 100% Load Factor	0.532 cents/kWh
General Service Demand	
@ Secondary Voltage	0.534 cents/kWh
@ Primary Voltage	0.529 cents/kWh
@ Transmission Voltage	0.523 cents/kWh
Curtailable	
@ Secondary Voltage	0.528 cents/kWh
@ Primary Voltage	0.523 cents/kWh
@ Transmission Voltage	0.517 cents/kWh
Interruptible	
@ Secondary Voltage	0.520 cents/kWh
@ Primary Voltage	0.515 cents/kWh
@ Transmission Voltage	0.510 cents/kWh
Lighting	0.529 cents/kWh

TECO:

Rate Class		Factor at Secondary Voltage (¢/kWh)
RS		0.460
GS, TS		0.460
GSD, SBF		
	Secondary	0.458
	Primary	0.453
	Transmission	0.449
IS		
	Secondary	0.450
	Primary	0.446
	Transmission	0.441
LS1		0.456
Average Factor		0.459

GULF:

RATE CLASS	ENVIRONMENTAL COST RECOVERY FACTORS ¢/KWH
RS, RSVP	1.294
GS	1.286
GSD, GSDT, GSTOU	1.273
LP, LPT	1.245
PX, PXT, RTP, SBS	1.227
OS-I/II	1.233
OSIII	1.255

H. We approve as reasonable the determination that the new factors shall be effective beginning with the first billing cycle for January 2012. The first billing cycle may start before January 1, 2012, and thereafter the environmental cost recovery factors shall remain in effect until modified by this Commission.

III. STIPULATED COMPANY-SPECIFIC ISSUES

Florida Power & Light

A. We approve as reasonable the following stipulation regarding whether FPL should be allowed to recover the costs associated with its proposed St. Lucie Cooling Water Monitoring Project:

Yes. This project is required to comply with Florida Department of Environmental Protection (FDEP) Administrative Order AO022TL (AO) and conditions in Industrial Wastewater (IWW) Permit No. FL0002208, which became effective on December 23, 2010, and relate to operation and limitations for the St. Lucie Plant Cooling Water System (CWS). The extended power uprate at St. Lucie Units 1 and 2 will result in an increased heat output which, in turn, will cause an increase in the discharge temperature of the plant's cooling water. FPL submitted to the FDEP a request to modify the IWW Permit in this regard. The FDEP has approved an increase in the current permitted discharge temperature limit, subject to FPL's complying with new study and monitoring requirements (and corrective action requirements if necessary) that are contained in the AO and IWW Permit. The proposed project meets the criteria for cost recovery

established by the Commission in Order No. PSC-94-0044-FOF-EI[2]. In addition, FPL's compliance with the IWW permit is legally mandated under a governmentally imposed environmental regulation.

The estimated total expenditures associated with the project are approximately $3 million, of which approximately $1.2 million has been included in the calculation of the 2012 ECRC factor. At this time, the project consists of preparing and implementing plans for (1) monitoring the ambient and CWS discharge water temperature, and (2) biological monitoring to demonstrate that conditions allow for the existence of a balanced, indigenous community of fish, shellfish and wildlife near the CWS discharge of the St. Lucie Plant. If any corrective actions are required as a result of the monitoring activities, FPL should petition the Commission to amend the project at that time for further ECRC cost recovery.

B. We approve as reasonable the following stipulation regarding how costs associated with FPL's proposed St. Lucie Cooling Water Monitoring Project should be allocated to the rate classes:

Capital and O&M costs for FPL's proposed St. Lucie Plant Cooling Water Discharge Monitoring Project should be allocated to the rate classes on an average 12 CP demand basis.

C. We approve as reasonable the following stipulation regarding whether FPL should be allowed to recover the costs associated with its proposed Industrial Boiler MACT Project:

Yes. This project is required by the United States Environmental Protection Agency (EPA), which regulates Hazardous Air Pollutants (HAPs) under Section 112 of the Clean Air Act (CAA) and promulgates emission standards for HAPs under 40 CFR Part 63 for stationary source categories. On February 21, 2011, the final Industrial/Commercial/Institutional Boiler Maximum Achievable Control Technology (IB MACT) rules were signed by the EPA Administrator. EPA's two rules address boilers and process heaters under Subpart DDDDD (40 CFR 63.7480) for affected units at major sources, and under Subpart JJJJJJ (40 CFR 63.11193) for affected units at area sources. The IB MACT rules impose new emission limitations, work practice standards, and operating limits on the affected source categories to reduce the emissions of HAPs. FPL's plans to comply with the requirements of these rules include developing site-specific monitoring plans, conducting emissions stack testing, performing fuel oil sampling and analyses, conducting biennial tune-up practices, performing one-time energy assessment, and installing emission controls or replacing existing units. Subpart JJJJJJ became effective on March 21, 2011. The EPA has stayed the effectiveness of Subpart DDDDD.

[2] Issued January 12, 1994, in Docket No. 930613-EI, In re: Petition to establish an environmental cost recovery clause pursuant to Section 366.0825, Florida Statutes by Gulf Power Company.

FPL estimated that the costs associated with complying with Subpart JJJJJJ are $41,453, and the costs associated with the complying with Subpart DDDDD are $337,895. FPL should be allowed to recover through the ECRC the Subpart JJJJJJ-related compliance costs. This portion of the proposed project meets the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI. In addition, FPL's compliance with the Subpart JJJJJJ is legally mandated under a governmentally imposed environmental regulation. FPL has removed the projected Subpart DDDDD costs from its 2012 ECRC projections and will petition to recover its reasonable and prudent 2012 compliance costs under Subpart DDDDD via ECRC true-up process for 2012.

D. We approve as reasonable the following stipulation regarding how costs associated with FPL's proposed Industrial Boiler MACT Project should be allocated to the rate classes:

Capital and O&M costs for FPL's proposed Industrial Boiler MACT Project should be allocated to the rate classes on an average 12 CP demand basis.

E. We approve as reasonable the following stipulation regarding whether FPL should be allowed to recover the costs associated with its proposed NPDES Permit Renewal Requirement Project:

Yes. This project is designed to comply with the Federal Clean Water Act, which requires all point source discharges to navigable waters from industrial facilities to obtain permits under the National Pollutant Discharge Elimination System (NPDES) program. (33 U.S.C. Section 1342) NPDES permits must be renewed every five years. The FDEP has been delegated authority by the EPA to implement the NPDES program in Florida. The FDEP has amended Rule 62-620.620 (3), F.A.C., to require that all new or renewed wastewater discharge permits for major facilities, including power plants, contain whole effluent toxicity (WET) limits. Additionally, the FDEP has required that facilities prepare a Storm Water Pollution Prevention Plan (SWPPP) that conforms to Rule 62-620.100 (m), F.A.C., and 40 CFR Part 122.44(k) when their NDPES permits are renewed. The proposed project is associated with these new requirements for WET monitoring and reporting, as well as for preparing Storm Water Pollution Prevention Plans that are or will be contained in the latest renewals for FPL's NPDES permits. The WET testing requirements of the project will be on-going. The estimated 2011 and 2012 O&M cost for compliance with the new WET testing requirement is approximately $77,000. The SWPPP activities of the proposed project are expected to be completed by 2014 and the current estimates of the total expenditures are $100,000 in O&M costs. The estimated 2011 and 2012 O&M costs for the development of SWPPPs at FPL's facilities are approximately $30,000. FPL's proposed project meets the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI. In addition, FPL's compliance with the NPDES permit is legally mandated under a governmentally imposed environmental regulation.

F. We approve as reasonable the following stipulation regarding how the costs associated with FPL's proposed NPDES Permit Renewal Requirement Project should be allocated to the rate classes:

Capital and O&M costs for FPL's proposed NPDES Permit Renewal Requirements Project should be allocated to the rate classes on an average 12 CP demand basis.

G. We approve as reasonable the following stipulation regarding whether FPL should be allowed to include the costs associated with its 800 MW ESP Project in its 2012 ECRC factor:

FPL has agreed to remove the projected 800 MW ESP Project costs from the calculation of its 2012 ECRC factors.

The EPA issued the proposed Air Toxics Rule (also referred to as the MACT Rule) on March 16, 2011, which was published in the Federal Register on June 21, 2011. FPL believes that the installation of ESPs at the Martin and Manatee plants is the most effective method to comply with the requirements of the proposed rule. FPL anticipates that the EPA will finalize the Air Toxics Rule by the November 16, 2011 deadline, in compliance with the D.C Circuit Court of Appeal's order.

In Order No. PSC-11-0083-FOF-EI, in Docket No. 100007-EI, issued January 31, 2011, Re: Environmental Cost Recovery Clause, the Commission approved a stipulation regarding whether FPL should be allowed to recover the costs associated with its proposed 800 MW ESP project for complying with the proposed MACT rule. Consistent with this order, FPL is authorized to include all the prudently incurred costs associated with the project in the normal process of ECRC recovery after the EPA publishes the final MACT rule. FPL will be allowed to recover reasonable and prudent ESP project costs via the ECRC true-up mechanism in the 2012 ECRC proceeding in the event that the final MACT rule requires ESPs and is adopted before or during 2012.

H. We approve as reasonable the following stipulation regarding whether FPL should be allowed to recover the costs associated with the additional activities required for the Manatee Temporary Heating System (MTHS) Project at Cap Canaveral Plant:

Yes. In Order No. PSC-09-0759-FOF-EI, in Docket No. 090007-EI, issued November 18, 2009, Re: Environmental Cost Recovery Clause, the Commission approved the MTHS-Cape Canaveral Plant project for cost recovery through the ECRC. FPL notified the Commission on January 4, 2011, that the heating system installed did not have enough thermal capacity to maintain the manatee embayment area at the necessary temperature to comply with the requirements of the FDEP's Industrial Wastewater Facility Permit FL0001473 for the Cape Canaveral Plant during periods of extreme cold. FPL determined that a light oil-fired water heating system (Supplemental Heating System) was the best solution to provide the incremental heating capacity needed in the event that the thermal capacity of the existing electric heating system is exceeded. Due to

the approximately two-week anticipated delivery time of the Supplemental Heating System, FPL also entered into a short-term lease for a smaller light oil-fired heater to be used at the Cape Canaveral Plant site during the extreme cold snap that Florida experienced in early December 2010. Once the reliability and effectiveness of the Supplemental Heating System was proven, FPL terminated the lease and returned the smaller heater. Other associated activities are the modification of discharge pipes in the primary heating system and the installation of booms to direct and control the flow of warm water in the embayment area.

I. We approve the following stipulation regarding whether we should approve FPL's updated Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Clean Air Visibility Rule (CAVR)/Best Available Retrofit Technology (BART) Projects that are reflected in FPL's April 1, 2011, supplemental filing as reasonable and prudent:

Yes. Completion of the compliance activities discussed in FPL's Supplemental CAIR/CAMR/CAVR Filing of April 1, 2011, is required by existing federal and state environmental rules and regulatory requirements at that time for air quality control and monitoring; and the associated project costs appear reasonable and prudent. On February 21, 2011, the EPA published final IB MACT rules, of which Subpart JJJJJJ became effective on March 21, 2011, and Subpart DDDDD was stayed. On March 16, 2011, the EPA issued the proposed Air Toxics Rule, also referred to as the MACT Rule. FPL anticipates that the EPA will finalize this Rule by the November 16, 2011 deadline, in compliance with the D.C Circuit Court of Appeal's order. On July 16, 2011, the EPA issued the Cross State Air Pollution Rule (CSAPR) which serves as the replacement for the CAIR rule. FPL shall continue to file, as part of its annual ECRC final true-up testimony, a review of the efficacy of its CAIR/CAMR/CAVR compliance plans. In its review, FPL shall update the Commission on the developments of the aforementioned new and/or proposed rules, as well as the cost-effectiveness of the company's retrofit options for each generating unit in relation to expected changes in environmental regulations. The reasonableness and prudence of individual expenditures, and FPL's decisions on the future compliance plans made in light of subsequent developments, will continue to be subject to the Commission's review in future ECRC proceedings on these matters.

Progress Energy Florida

A. We approve as reasonable the following stipulation regarding whether we should grant PEF's Petition for approval of ECRC cost recovery for the National Pollutant Discharge Elimination System (NPDES) Permit Renewal Requirement Project:

Yes. This project is necessary to comply with renewed NPDES permits issued or to be issued for PEF's facilities by the FDEP pursuant to the EPA approved NPDES permitting program in Florida and applicable FDEP regulations. The new compliance requirements included in the Bartow, Anclote, Crystal River, and Suwannee permits are composed of Thermal Studies, Aquatic Organism Return Studies & Implementation, and Whole

Effluent Toxicity Testing (WET). For the Bartow Plant, there are additional regulatory requirements and activities, including a Dissolved Oxygen Study and freeboard Limitation and Related Studies. The proposed project meets the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI. In addition, PEF's compliance with the NPDES permit is legally mandated under a governmentally-imposed environmental regulation. The Company estimated that the total costs for complying with the new NPDES permit requirements are approximately $1.5 million for the period of 2011 through 2012. PEF indicated that costs for the chronic WET testing would recur annually. It also indicated that costs for implementing the various studies cannot be estimated at this time, but would be submitted for Commission review and approval at the appropriate time in future ECRC filings.

B. We approve as reasonable the following stipulation regarding how the costs associated with PEF's proposed NPDES Permit Renewal Requirement Project should be allocated to the rate classes:

Capital costs for the NPDES project should be allocated to rate classes on a demand basis. O&M costs for the project should be allocated to the rate classes on an energy basis.

C. We approve as reasonable the following stipulation regarding whether we should grant PEF's Petition for approval of ECRC cost recovery for the Maximum Achievable Control Technology (MACT) Project:

Yes. On March 16, 2011, the EPA issued a proposed Electric Generating Unit (EGU) MACT Rule. In accordance with a D.C Circuit Court of Appeal's order, the EPA Administrator will sign a final rule by November 16, 2011. Adoption of the new EGU MACT rule will require PEF to modify its Integrated Clean Air Compliance Plan, which was approved by the Commission in the previous year's ECRC hearings, to comply with new emission standards. The proposed new activities for 2011 include diagnostic stack testing, and emissions testing at Crystal River Units 4 and 5 to assess emissions of mercury, HCl and condensable particulate matter while testing hydrated lime injection and various operational conditions. Upon issuance of the final EGU MACT rule, PEF will conduct detailed engineering and other analyses necessary to develop compliance strategies for inclusion in an updated Integrated Clean Air Compliance Plan. The proposed project meets the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI, and is consistent with the Commission's decision set in Order No. PSC-08-0775-FOF-EI.[3] In addition, PEF's proposed activities are necessary for the Company to assess the proposed rule, prepare comments to the EPA, and develop compliance strategies within aggressive regulatory timeframes. The estimates of the O&M costs associated with this Project are approximately $85,000 in 2011 and $300,000 for 2012.

[3] Issued November 24, 2008, in Docket No 080007-EI, In re: Environmental cost recovery clause.

D. We approve as reasonable the following stipulation regarding how the costs associated with PEF's proposed MACT Project should be allocated to the rate classes:

O&M costs for the MACT Project should be allocated to the rate classes on an energy basis.

E. We approve as reasonable the following stipulation regarding whether we should approve PEF's proposed treatment of its CAIR-related NOx allowances:

On July 16, 2011, the EPA issued the Cross State Air Pollution Rule (CSAPR) to replace the Clean Air Interstate Rule (CAIR) starting January 1, 2012. The new rule significantly alters the SO2 and NOx allowance programs. Under the CAIR, Florida was required to comply with the requirements related to emissions of SO2 and NOx, as well as separate requirements regulating NOx emissions during the ozone season. Under the CSAPR, Florida is no longer included in the group of states required to comply with SO2 and NOx emissions requirements; it is only subject to the ozone season portions of the rule. The effective compliance start day for Florida is May 1, 2012, when the ozone season begins. Moreover, the emission allowances previously issued to utility companies under CAIR and/or the Acid Rain Program cannot be used to comply with CSAPR requirements.

Since any NOx allowances not used by the end of 2011 are not expected to be useful for compliance with the new CSAPR rule, PEF proposes to treat its approximately $22.5 million of NOx allowances in inventory as a regulatory asset as of January 1, 2012, and amortize it over the course of 2012 until fully recovered at year end, with a return on the unamortized balance of the emission allowances during 2012. PEF asserts that all of the $22.5 million was incurred purchasing NOx allowances and represents investments PEF has made in this inventory.

CAIR established new seasonal and annual emission compliance requirements for NOx. Beginning in 2009, CAIR required affected sources to complete a seasonal NOx emission allowance submittal for the May 1 through September 30 time period and annual NOx emission allowance compliance submittal for the January 1 through December 31 time period each year. When PEF first asked the Commission to approve its Integrated Clean Air Compliance Plan in March 2006, its detailed economic analyses of five potential compliance scenarios indicated that its "Plan D," which relied on strategic purchases of annual and seasonal NOx allowances, rather than installing NOx controls on Crystal River Units 1 and 2, was the most cost-effective option for compliance with CAIR and related regulatory requirements. In the 2007 ECRC docket, PEF submitted updated economic analyses confirming that Plan D, which included its reliance on NOx allowance purchases, was the most cost-effective option. The Commission agreed that "PEF's Integrated Clean Air Compliance Plan represents the most cost-effective alternative for achieving compliance with CAIR, CAMR CAVR."[4] In the subsequent years, 2008

[4] Order No. PSC-07-0922-FOF-EI, issued November 16, 2007, in Docket 070007-EI, In re: Environmental Cost Recovery.

through 2010, PEF updated the Commission annually on its Integrated Clean Air Compliance Plan, each of which included strategic NOx allowance purchases and were granted approval. Therefore, PEF's purchases of NOx allowances were pre-approved by the Commission.

The evidence in this docket indicates that PEF exercised a prudent NOx emissions allowance strategy. During the relevant time period, in order to determine if PEF would need to purchase seasonal and annual NOx emission allowances, the Company compared its total seasonal and annual NOx emissions projections from fuel and generation forecasts to the number of the allowances held by PEF, which included allowance allocations from the EPA, purchases made over time, and allowances carry-overs. In the aggregate, if the number of allowances that PEF would need to comply with CAIR based on forecasted emissions was greater than the number of allowances PEF held, the Company purchased additional allowances in the market. The historical data of PEF's allowance purchases, inventories and expenses submitted by the Company, indicates that PEF acted prudently in implementing its procurement strategy of purchasing NOx allowances over time, to gradually increase inventory levels based on emission forecasts developed using the best information available at the time.

Based on the above, the $22.5 million investment associated with PEF's NOx allowances under the CAIR was prudently incurred under a Commission-approved environmental compliance plan. It is appropriate for PEF to treat these $22.5 million now-unusable NOx allowances as a regulatory asset and recover them through the ECRC. However, the amortization period should be a three-year amortization period, so as to reduce the volatility in customer bills while balancing the level of carrying costs associated with the $22.5 million investment. Recognizing that historically many of the EPA's final rules were subsequently challenged in court after their publication, the CSAPR rule too may be litigated and ultimately revised in the future. If there are changes to the CSAPR that result in the $22.5 million NOx allowances regaining value, PEF should refund the amount it recovered associated with these NOx allowances through the ECRC, and expense the amount into the ECRC based on actual usage consistent with current practice.

F. We approve as reasonable the following stipulation regarding whether we should approve PEF's updated Review of Integrated Clean Air Interstate Rule Compliance Plan that was submitted on April 1, 2011:

Yes. PEF's Updated Integrated Clean Air Compliance Plan is a reasonable means to achieve timely compliance with the applicable regulations in a cost-effective manner. All of the major components of the Crystal River Units 4 and 5 emissions control projects included in PEF's Integrated Clean Air Compliance Plan have been completed. PEF shall continue evaluating future compliance options in light of the EPA's recently finalized CSAPR rule and proposed EGU MACT standards for coal and oil-fired generating units. Once the EGU MACT rule is finalized and the Company determines its most cost-effective compliance options, PEF should submit revisions to PEF's Integrated

Clean Air Compliance Plan to the Commission for review. The revised Plan should discuss the impacts and estimated costs associated with PEF's integrated strategy for complying with CSAPR, MACT and related environmental regulatory programs. The reasonableness and prudence of PEF's decisions on the future compliance plans made in light of subsequent environmental rule and regulation developments, will continue to be subject to the Commission's review in future ECRC proceedings on these matters.

Gulf Power Company

A. We approve as reasonable the following stipulation regarding whether Gulf should be allowed to recover the costs associated with its proposed Impoundment Integrity Inspection Project:

Yes. The proposed project addresses costs associated with Gulf's compliance with a new condition in the Plant Crist National Pollutant Discharge Elimination System (NPDES) permit renewal issued during January of 2011. This new condition requires inspection of all ash impoundments at Plant Crist annually. These inspections must include observations of dike and toe areas for erosion, 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 and any other change which may indicate a potential compromise to impoundment integrity. The permit condition requires that summarized findings of all monitoring activities, inspections, and corrective actions pertaining to the impoundment integrity, and operation and maintenance of all impoundments must he documented and kept onsite and made available to FDEP inspectors. All findings and corrective actions related to impoundment integrity at Plant Crist must be complied with per the permit condition. The proposed project meets the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI. In addition, Gulf's compliance with the NPDES permit is legally mandated under a governmentally imposed environmental regulation. The estimated costs associated with the project will total $156,000 during 2012.

B. We approve as reasonable the following stipulation regarding how the costs associated with Gulf's proposed Impoundment Integrity Inspection Project should be allocated to the rate classes:

The costs associated with this project shall be allocated to the rate classes on an average 12 CP demand and 1/13th energy basis.

C. We approve as reasonable the eight page stipulation regarding whether Gulf should be allowed to recover the costs associated with the Plant Crist Units 6 and 7 turbine upgrades. The stipulation, filed in this docket on October 28, 2011, and assigned Document No. 07947, and is hereby incorporated in this Order by reference and attached hereto as Attachment 1.

D. We approve as reasonable the following stipulation regarding whether this Commission should approve Gulf's proposed treatment of its CAIR-related NOx allowances:

Yes. On July 16, 2011, the EPA issued the CSAPR rule to replace the CAIR rule starting January 1, 2012. It appears that the annual NOx emission allowances previously issued to Florida utility companies under CAIR and/or the Acid Rain Program cannot be used to comply with CSAPR requirements, and Florida is no longer included in the group of states required to comply with annual NOx emissions requirements. As reported in Gulf's Schedule 8E, filed on August 1, 2011, and Schedule 4P, filed on August 26, 2011, the Company will have approximately $1.3 million of annual NOx allowances as of December 31, 2011. Gulf indicated in its response to Staff's Fourth Set of Interrogatories, No. 6a, that "[a] decision as to whether or not the balance of annual NOx allowances on hand at the end of 2011 will have any value in the future is yet to be determined pending potential litigation related to the new Cross State Air Pollution Rule (CSAPR). Regardless of whether these allowances are ultimately deemed to have any value or not beyond 2011, the costs of these allowances were prudently incurred expenses that are recoverable through the Environmental Cost Recovery Clause."

It is reasonable for the Company to have a "waiting period" to obtain more information before making a decision on how to treat its CAIR-related annual NOx allowances on hand. Gulf should update the Commission, in a timely manner, on the Company's decision on how it proposes to treat its remaining annual NOx allowances inventory in light of the future developments in the CSAPR. It is reasonable to limit this "waiting period" to a three-year time frame so that it would not result in a significant amount of carrying costs associated with this $1.3 million capital investment being incurred.

E. We approve as reasonable the following stipulation regarding whether this Commission should approve Gulf's Environmental Compliance Program Update that was submitted on April 1, 2011:

Yes. Gulf's updated Environmental Compliance Program reflects a comprehensive assessment of requirements Gulf and its customers face in meeting various existing environmental rules and the pending EGU MACT rule. In assessing the most cost-effective means of meeting these significant regulatory requirements, the Company considered four primary compliance options: fuel switching, purchase of allowances, retrofit installations, and retirement and replacement of existing units. Based upon comprehensive technical and economic evaluations of alternatives, Gulf assessed the best means of meeting plan-by-plan emission requirements through retrofit measures supplemented by allowance purchases and compared those options to retiring and replacing existing units. It appears that Gulf's Environmental Compliance Program is the most reasonable and cost effective option available to Gulf under the planning assumptions at that time.

On July 16, 2011, the EPA issued the Cross State Air Pollution Rule (CSAPR) which serves as the replacement for the CAIR rule. According to the Company's response to

Staff's Fifth Set of Interrogatories No. 10c, filed September 26, 2011, Gulf's current strategy to comply with CSAPR relies on the ability to purchase allowances above the annual allowances provided to the company or to import power to supplement Gulf's territorial load; Gulf will continue to evaluate these options pursuant to the development of the seasonal emission allowance market and the availability of purchased power agreements. Gulf also indicated that it is currently evaluating the existing particulate emission controls (ESPs) at Plant Crist and Daniel to determine whether they will be able to ensure compliance with the EGU MACT rule. Once the rule is finalized, Gulf will be able to determine whether or not the existing controls will be adequate or if a baghouse(s) will have to be installed.

Gulf should continue to evaluate future compliance options in light of the EPA's recently finalized CSAPR rule and the EGU MACT standards. Once the EGU MACT rule is finalized and the Company determines its most cost-effective compliance options, Gulf should submit for the Commission's review revisions to Gulf's Environmental Compliance Program. The revised Program should discuss the impacts and estimated costs associated with Gulf's integrated strategy for complying with CSAPR, EGU MACT and related environmental regulatory programs. The reasonableness and prudence of individual expenditures, and Gulf's decisions on the future compliance plans made in light of subsequent environmental rule and regulation developments, will continue to be subject to the Commission's review in future ECRC proceedings on these matters.

IV. CONTESTED COMPANY-SPECIFIC ISSUES[5]

We have been asked to determine whether PEF should be permitted to recover any environmental costs related to its purchases of replacement power due to the Crystal River 3 outage. This determination affects the final calculation of numbers in stipulated issues throughout this case.

PEF is experiencing an unplanned extended outage at its Crystal River Nuclear Unit 3 (CR3) that started in mid-December 2009. FIPUG has questioned whether PEF should be permitted to recover any environmental costs related to its purchases of replacement power due to the CR3 extended outage. The environmental costs in question are emission allowances. The record reflects that no allowance purchases have been made associated with replacement power due to the CR3 extended outage and that PEF has made no allowance purchases since May of 2009. Therefore, we find that the dollar amount associated with this issue, which is the costs of the emission allowances related to the purchases of replacement power due to the CR3 extended outage, is zero.

[5] PEF filed a Post-Hearing Brief in this docket. The Office of Public Council (OPC), FIPUG, and the Federal Executive Agencies (FEA) (collectively, Consumer Intervenors) filed a Joint Post-Hearing Brief of Intervenors (Consumers Brief) in this docket and in Docket No. 110001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

However, during the hearing, the Consumer Intervenors – ancillary to the issue as framed - questioned whether PEF should be permitted to recover the environmental costs related to its replacement power costs incurred due to the CR3 extended outage, rather than the cost of any purchased emission allowances due to the CR3 extended outage. The replacement power costs due to the CR3 extended outage consist of two portions: the purchased replacement power and self-generated replacement power. Although there were no environmental costs incurred associated with purchases of replacement power due to the CR3 extended outage, there were environmental costs, namely the costs of the emission allowances, associated with the self-generated portion of the replacement power. The table below reflects the estimated system expense associated with previously purchased emission allowances that were used for the purpose of generating replacement power due to the CR3 extended outage. These costs were included in PEF's projected 2012 factor. The Consumer Intervenors have not contested the amounts shown in the table below.

Emission Allowances Associated with CR3 Extended Outage	
2010	$2,453,542
2011	$1,191,999
2012	$(957,130)
Total	$2,688,411

The Consumer Intervenors oppose the recovery of the emission allowances related to the replacement power due to the CR3 extended outage. They assert that PEF should not be permitted to recover any further costs related to the CR3 extended outage until the prudence issues in Docket No. 100437-EI are resolved and conclude that we should deny PEF's request to recover any costs resulting from the outage of the CR3 nuclear power plant until we determine in Docket No. 100437-EI whether the events or actions leading to the CR3 outage were reasonable and prudent.

PEF asserts that PEF's emission allowance costs are reasonable and recoverable; that this Commission has determined that the evidence in this docket indicates that PEF followed a prudent NOx emission allowance strategy; that allowing CR3 extended outage-related environmental cost recovery prior to a determination of prudence is constitutional; that deferral of recovery of emission allowance costs associated with the CR3 replacement power would contravene established Commission precedent and policy; and that,

> by approving the stipulation of [Hearing] Issue 10E in this docket, the Commission established a regulatory asset to allow PEF to recover the cost of surplus NOx allowances in its inventory over a 3 year period. . . . The establishment of the regulatory asset effectively moots any issue in this

> proceeding regarding NOx allowance costs because had PEF not utilized the NOx allowances associated with the CR3 replacement power, they would have remained in inventory and been recovered through the regulatory asset.

Our practice in the environmental clause proceedings, as well as our other clause proceedings, has been to allow recovery of projected costs, which are then subject to true-up adjustments based on actual costs incurred. Subsequently, we may disallow costs if a finding of imprudence is made. This practice allows cost recovery in a timely manner while protecting ratepayers by conducting a separate review for potential disallowance. Each year we determine the next year's ECRC factor based on three types of costs: (1) final true-up amounts which are known to have been incurred during the prior year; (2) current period true-up amounts which consist of a half-year's actual and a half-year's estimated costs; and (3) projected amounts which are, of course, completely estimated costs. Thus, ECRC revenues, as well as those of all the other clauses, are collected from customers on a projected basis and subject to refund. We approve cost recovery amounts for the next calendar year based upon estimates of the costs that will be incurred during that year. Estimates are never exact, so it is to be expected that there will be some variance between a utility's initial cost estimates and its actual costs. Accordingly, the cost recovery amounts approved for developing rates for the projected year will not only include the initial cost estimates for that year, but also a true-up of costs previously approved for recovery during the current year. The true-up process addresses the variances which occur between initial cost estimates and actual costs over a moving three-year period.

PEF's Method of Accounting and Expensing of Emission Allowances

As part of its Clean Air Interstate Rule (CAIR) compliance program, PEF has maintained emission allowance inventories. Some of these allowances were allocated by the Environmental Protection Agency (EPA) to PEF at no cost, and the rest were purchased by PEF in the market. PEF books to inventory at zero cost the allowances the EPA gave to PEF at no charge, and does not impute a value for any allowances based on market conditions. PEF values its overall pool of allowances at average cost, and expenses these allowances to meet emission compliance requirements using an average cost method.

FIPUG questions the appropriateness of PEF using the average cost inventory valuation method, rather than a First In First Out (FIFO) method, for the accounting and expensing of emission allowances. PEF explains that the average cost method is recognized by the FERC and GAAP as an acceptable method of valuing inventories, and PEF uses this method not only for its emission allowance inventory, but also for its fuel inventories. PEF has employed the average cost approach for its emission allowance accounting and expensing since the beginning of the emission compliance program, and has not implemented any accounting changes related to emission allowances due to the CR3 extended outage.

The Consumer Intervenors assert that PEF has sufficient zero-cost allowances to offset all emissions related to the CR3 extended outage and that use of FIFO would result in no charge to ratepayers for these credits. The Consumer Intervenors assert that it is inappropriate for PEF to use the average market approach and allocate additional costs to ratepayers when no amount was

paid for the CR3-related emission allowances. The Consumer Intervenors conclude that we should reject the average cost accounting approach used by PEF in favor of the first in, first out approach.

PEF asserts that it would be inappropriate to pick and choose an accounting methodology just to obtain the result advocated by the Consumer Intervenors. Further, PEF argues that,

> even if one accepts Interveners' [sic] argument that the allowances attributed to the CR3 extended outage should be expensed at zero, there is an impact of increased cost on PEF's other allowances which must be taken into account. This impact to the cost of the other allowances that PEF expensed during this time period is unknown and not part of the record evidence. Thus, the Commission cannot base any decision on a FIFO methodology, even assuming that such a change in methodology could somehow be warranted.

PEF concludes that we should not arbitrarily change the established methodology used to account for its emission allowance costs. Moreover, PEF asserts that pursuant to the Order Establishing Procedure, the Consumer Intervenors waived this accounting methodology issue because they failed to raise it before the Prehearing Conference.

We note that the Order Establishing Procedure provides the following:

> Any issue not raised by a party either before or during the Prehearing Conference shall be waived by that party, except for good cause shown. A party seeking to raise a new issue after the Prehearing Conference shall demonstrate each of the following:
>
> (1) The party was unable to identify the issue because of the complexity of the matter.
> (2) Discovery or other prehearing procedures were not adequate to fully develop the issue.
> (3) Due diligence was exercised to obtain facts touching on the issue.
> (4) Information obtained subsequent to the Prehearing Conference was not previously available to enable the party to identify the issue.
> (5) Introduction of the issue would not be to the prejudice or surprise of any party. [6]

Upon review, we find that there is no testimony or other record evidence supporting a change in PEF's accounting practices with respect to emission allowances. Moreover, this matter was never raised as an issue at the Prehearing Conference. Thus, we find that it is appropriate and reasonable for PEF to use the average cost valuation method to manage the accounting and expensing of its emission allowance inventories.

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[6] Order No. PSC-11-0150-PCO-EI at 6, issued March 4, 2011, in this docket.

Constitutional Issues

Upon review, we decline to address constitutional issues raised by the Consumer Intervenors. Such issues may be raised at the Florida Supreme Court, *de novo,* on appeal.

Regulatory Asset for the Emission Allowances

As discussed above, PEF asserts that the establishment of the regulatory asset for NOx emission allowances effectively moots any issue in this proceeding regarding NOx allowance costs. If PEF had not utilized the NOx allowances associated with the CR3 replacement power, those allowances would have remained in inventory and then been recovered through the regulatory asset. As a result, the major portion of the CR3 extended outage-related environmental expenses shown in table on page 17 of this Order will be recovered through the ECRC regardless of our decision on this issue. Upon review, we find that the amounts shown in the table shall be included in the 2012 ECRC factors.

Conclusion

Upon review, we find that, based on the record evidence, PEF did not incur any environmental costs, specifically allowance purchases, associated with purchases of replacement power due to the CR3 extended outage; therefore, there are no costs to recover. The amounts reflected in the table above shall be included in PEF's 2012 ECRC factors

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the stipulations and findings set forth in the body of this order are hereby approved. It is further

ORDERED that each utility that was a party to this docket shall abide by the stipulations and findings herein which are applicable to it. It is further

ORDERED that Progress Energy Florida, Inc. did not incur any environmental costs, specifically allowance purchases, associated with purchases of replacement power due to the CR3 extended outage; therefore, there are no costs to recover. It is further

ORDERED that the utilities named herein are authorized to collect the environmental cost recovery amounts and use the factors approved herein beginning with the first billing cycle for 2012. The first billing cycle may start before January 1, 2012, and thereafter, the environmental cost recovery factors shall remain in effect until modified by this Commission. It is further

ORDERED that the Environmental Cost Recovery Clause docket is an on-going docket and shall remain open.

By ORDER of the Florida Public Service Commission this 7th day of December, 2011.

ANN COLE
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
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CWM

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT 1

STIPULATION AND AGREEMENT REGARDING ISSUES RELATED TO COST RECOVERY OF PLANT CRIST TURBINE UPGRADES AND JOINT REQUEST FOR APPROVAL

Document No 07947-11
Filed October 28, 2011

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause. In re: Petition for increase in rates by Gulf Power Company.	DOCKET NO. 110007-EI DOCKET NO. 110138-EI

STIPULATION AND AGREEMENT REGARDING ISSUES RELATED TO COST RECOVERY OF PLANT CRIST TURBINE UPGRADES AND JOINT REQUEST FOR APPROVAL

The Citizens of the State of Florida, through the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Federal Executive Agencies ("FEA"), the Florida Retail Federation ("FRF") and Gulf Power Company ("Gulf Power", "Gulf", or "the Company"), (collectively, the "Parties"), through their respective undersigned counsel, hereby jointly petition the Florida Public Service Commission for entry of an order approving this stipulation regarding the issues of cost recovery associated with turbine upgrades at Gulf's Plant Crist undertaken or planned by Gulf in connection with the Company's Flue Gas Desulfurization ("Scrubber") Project at Plant Crist. The Parties represent that this stipulation fairly and reasonably balances the various positions of the Parties and serves the best interests of the customers they represent and the public interest in general and, therefore, is fully consistent with and supportive of the Commission's long standing policy of encouraging the settlement of contested proceedings in a manner that benefits the ratepayers of utilities subject to the Commission's regulatory jurisdiction and thereby avoids the need for costly, time-consuming and inefficient litigation of matters before the Commission.

BACKGROUND

The Plant Crist Units 4 through 7 Scrubber Project has been developed by Gulf under its CAIR/CAMR/CAVR Compliance Program which was approved for cost recovery through the Environmental Cost Recovery Clause ("ECRC") pursuant to a stipulation dated June 22, 2007 ("2007 Stipulation") between the Parties and the Florida Industrial Power Users Group ("FIPUG") that was approved by the Commission in Order No. PSC-07-0721-S-EI, issued September 5, 2007, In re: Environmental Cost Recovery.

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

Subsequent to entering into the 2007 Stipulation, Gulf decided to install turbine upgrades for Crist Units 6 and 7 as part of the Company's implementation of the Plant Crist Scrubber Project to offset increased station service requirements associated with the scrubber installation. Gulf incorporated the costs associated with the upgrades in its planning process for the Scrubber Project and reflected these costs in all of its updates to Gulf's CAIR/CAMR/CAVR Compliance Program filed with the Commission pursuant to the order approving the 2007 stipulation beginning with the update filed in 2008. Gulf referenced these upgrades in its witness testimony in the ongoing ECRC docket beginning with testimony filed in August 2008.

A dispute has arisen among the parties regarding whether the costs associated with the turbine upgrades are properly within the scope of the 2007 Stipulation or otherwise meet the criteria for recovery through the Environmental Cost Recovery Clause. The following issue has been identified in Docket No. 110007-EI for the hearings in that docket scheduled for November 1, 2 and 3, 2011:

> Issue 11C: Should Gulf be allowed to recover the costs associated with the Plant Crist Units 6 and 7 turbine upgrades?

The following issue has tentatively been identified as part of Staff's preliminary list of issues in Docket No. 110138-EI scheduled for hearing December 12-16, 2011:

> Should the Plant Crist Units 6 and 7 Turbine Upgrade Project be included in rate base and recovered through base rates, rather than through the Environmental Cost Recovery Clause?

STIPULATION

WHEREAS the Parties agree that a dispute exists regarding the appropriateness of the Crist 6 and 7 turbine upgrades for recovery through the ECRC;

WHEREAS the Parties agree that consideration of the Crist 6 and 7 turbine upgrades for recovery through Gulf's base rates is appropriate if recovery is not provided through the ECRC;

WHEREAS the Parties agree that in order to resolve their differences, recovery of the Crist 6 and 7 turbine upgrades through the ECRC should be discontinued on a prospective basis beginning with the ECRC recovery factors to be applied during 2012, and recovery on a

prospective basis should be provided through the base rates to be established for Gulf Power Company in Docket No. 110138-EI;

WHEREAS the parties agree that as part of the transition from ECRC recovery to base rate recovery, the parties should be allowed an opportunity to address the amount of recovery through base rates through the filing of supplemental testimony in Gulf's rate case, Docket No. 110138-EI;

WHEREAS, in current Docket No. 110138-EI, involving Gulf Power's petition for authority to increase its base rates, Gulf Power removed the investment and expenses associated with the turbine upgrades from test year rate base and expenses in view of Gulf Power's request to recover for these costs through the Environmental Cost Recovery Clause;

WHEREAS, in prefiled testimony submitted in Docket No. 110138-EI, Gulf Power's witness stated that, in the event the Commission denies recovery of costs associated with the Crist turbine upgrades through the Environmental Cost Recovery Clause, Gulf Power would wish to reverse the ratemaking adjustments in the base rate proceeding so as to include the investment and costs in the test year under consideration in that docket;

WHEREAS, in the absence of an agreement of parties and action by the Commission, no procedural mechanism exists that would accommodate the resolution of the dispute which otherwise has the potential to unnecessarily complicate the proceedings pending before the Commission; and,

WHEREAS, to avoid the necessity of, and inefficiency associated with, litigating the issues related to the investment and costs associated with the turbine upgrades in two separate proceedings, while assuring the subject is presented to the Commission in a manner that is fair to all concerned, the undersigned parties have reached an agreement that will facilitate the

Commission's resolution of all remaining potential issues between the parties regarding the turbine upgrades as part of the pending rate case;

WHEREAS the Parties agree that allowing Gulf the opportunity to file supplemental testimony in Docket No. 110138-EI followed by an opportunity for other parties to respond through testimony and an opportunity for Gulf to then file rebuttal testimony is an appropriate means of allowing the parties to address the issues regarding recovery for the turbine upgrades through base rates; and

WHEREAS the Parties agree that the relief requested in this stipulation is a reasonable resolution of the dispute between the parties;

NOW THEREFORE, based on the foregoing background and recitals, and discussions among the Parties, the Parties stipulate and agree to the following:

1. Gulf's final environmental cost recovery true-up amount for the period ending December 31, 2010 of $861,325 over-recovery as filed in Docket No. 110007-EI will not be opposed by any party to this stipulation.

2. Gulf's estimated environmental cost recovery true-up amount for the period January 2011 through December 2011 of $14,380,513 over-recovery as filed in Docket No. 110007-EI will not be opposed by any party to this stipulation.

3. Gulf's projected environmental cost recovery amount for the period January 2012 through December 2012 previously filed as $169,103,827 shall be revised to $165,075,432 which reflects the removal of all prospective revenue requirements from the ECRC for any of the Crist turbine upgrades and this revised amount will not be opposed by any party to this stipulation.

4. Gulf's total environmental cost recovery amount, including true-up amounts, for the period January 2012 through December 2012 previously filed as $153,861,989 (excluding revenue taxes) shall be revised to $149,833,594 (excluding revenue taxes) which reflects the

removal of all prospective revenue requirements from the ECRC for any of the Crist turbine upgrades and this revised amount will not be opposed by any party to this stipulation.

5. Based on the foregoing changes, Gulf's proposed environmental cost recovery factors for the period January 2012 through December 2012 for each rate group shall be revised to match the values in the following table and these revised amounts will not be opposed by any party to this stipulation:

RATE CLASS	ENVIRONMENTAL COST RECOVERY FACTORS ¢/KWH
RS, RSVP	1.294
GS	1.286
GSD, GSDT, GSTOU	1.273
LP, LPT	1.245
PX, PXT, RTP, SBS	1.227
OS-I/II	1.233
OSIII	1.255

6. As a result of the foregoing removal of the turbine upgrades from the ECRC recovery mechanism on a going forward basis, the only remaining dispute between the Parties is related to the revenue requirement amount that should be included in base rates thereof which shall be addressed by the Commission in Docket No. 110138-EI

7. Gulf Power shall be permitted an opportunity to submit supplemental pre-filed direct testimony and exhibits for the purpose of and limited to addressing the amount and timing of Gulf's investment in the turbine upgrades, the reasonableness of the associated investment and costs, and the extent to which the related investment and costs should be reflected in the revenue requirements the Commission will determine (and the base rates the Commission will prescribe) for Gulf Power in Docket No. 110138-EI. Such supplemental pre-filed direct testimony shall be

filed by Gulf and electronically served on all parties to Docket 110138-EI and Staff no later than November 8, 2011.

8. In response to any supplemental direct testimony and exhibits filed by Gulf Power pursuant to this stipulation, intervenors and Staff shall likewise be permitted an opportunity to submit supplemental pre-filed direst testimony and exhibits subject to the same limitations and scope outlined in paragraph 6 above. Such intervenor testimony shall be filed and electronically served on all parties to Docket 110138-EI and Staff no later than November 15, 2011. Such Staff testimony shall be filed and electronically served on all parties to Docket 110138-EI no later than November 22, 2011.

9. Gulf Power shall be permitted an opportunity to submit rebuttal testimony and exhibits to any supplemental testimony and exhibits submitted by intervenors or staff pursuant to this stipulation. Such supplemental rebuttal testimony shall be filed and electronically served on all parties to Docket 110138-EI and Staff no later than November 29, 2011.

10. All witnesses who prefile testimony and/or exhibits related to the turbine upgrades shall include with the filing any calculations, work papers, or underlying source documents that the sponsoring parties can reasonably foresee would be needed by other parties or Commission Staff to evaluate the testimony or exhibits. The undersigned parties agree to use best efforts to cooperate with respect to the prompt service of and expedited responses to discovery requests associated with prefiled testimony and exhibits submitted pursuant to this Stipulation and Agreement, to include, upon request, making the witness(es) available for deposition on an expedited basis, with the view of ensuring that all parties and Commission Staff have an adequate opportunity to prepare for the hearing on the matters that are the subject of this Stipulation and Agreement.

11. All parties to Docket No. 110138-EI shall endeavor to include statements of their positions on the issue or issues related to the turbine upgrades as part of their prehearing statements which shall remain due on the date set forth in the Order Establishing Procedure. The parties shall be allowed a reasonable opportunity to modify their position(s) to conform to their testimony filed after the due date for their testimony by communicating such modifications to the Commission Staff for inclusion in the Prehearing Order as quickly as possible, but no later than the Prehearing Conference scheduled for November 21, 2011.

12. This Stipulation and Agreement shall become effective immediately upon approval by the Commission. By entering this Stipulation and Agreement, no party waives or concedes any position on the merits of the matters that are the subject of the Stipulation and Agreement, and each party reserves the right to present and support any position regarding the substance of the issues that it determines is consistent with its interests. Each of the undersigned parties agrees to support the approval of the Stipulation and Agreement as serving the objectives of enhancing the efficiency of Commission proceedings and avoiding unnecessary litigation, and as consistent with the public interest.

[REMAINDER OF THIS PAGE INTENTIONALLY LEFT BLANK]

WHEREFORE, the undersigned parties agree and stipulate to the above terms and provisions, and together request the Commission to approve this Stipulation and Agreement at its earliest opportunity.

Respectfully Submitted,

Office of Public Counsel

By_____
Joseph A. McGlothlin, Esquire
Florida Bar No. _____
Associate Public Counsel

Patricia A. Christensen, Esquire
Florida Bar No. 0989789
Associate Public Counsel

111 W. Madison Street, Room 812
Tallahassee, Florida 32399
(850) 488-9330

Florida Industrial Power Users Group

By_____
John C. Moyle, Jr. Esquire
Florida Bar No._____
Vicki Gordon Kaufman, Esquire
Florida Bar No._____
Keefe, Anchors, Gordon & Moyle, PA
118 North Gadsden Street
Tallahassee, Florida 32301
(850) 681-3828

Gulf Power Company

By_____
Jeffrey A. Stone, Esquire
Florida Bar No. 325953
Beggs & Lane
Post Office Box 12950
Pensacola, FL 32576-2950
(850) 432-2451

Federal Executive Agencies

By_____
Karen White, Esquire
Major Christopher C. Thompson
AFCESA
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403
AFLONJACL-ULT
Ph: (850) 283-6348

Florida Retail Federation

By_____
Robert Scheffel Wright, Esquire
Florida Bar No._____
John T. Lavia, Esquire
Florida Bar No._____
225 South Adams Street, Suite 200
Tallahassee, Florida 32301
(850) 222-7206

WHEREFORE, the undersigned parties agree and stipulate to the above terms and provisions, and together request the Commission to approve this Stipulation and Agreement at its earliest opportunity.

Respectfully Submitted,

Office of Public Counsel

By: Joseph A. McGlothlin
Joseph A. McGlothlin, Esquire
Florida Bar No. _____
Associate Public Counsel

Patricia A. Christensen, Esquire
Florida Bar No. 0989789
Associate Public Counsel

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(850) 488-9330

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Florida Bar No. _____
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Gulf Power Company

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Jeffrey A. Stone, Esquire
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Federal Executive Agencies

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Florida Bar No. _____
225 South Adams Street, Suite 200
Tallahassee, Florida 32301
(850) 222-7206

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Petition for Increase in Rates by Gulf Power Company) Docket No. 110138-EI

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by electronic mail the 28th day of October, 2011, on the following:

Office of Public Counsel
J. R. Kelly/Joseph A. McGlothlin/Erik Sayler
c/o The Florida Legislature
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Caroline Klancke
Keino Young
Martha Barrera
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BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 110007-EI ORDER NO. PSC-11-0553A-FOF-EI ISSUED: December 13, 2011

AMENDATORY ORDER

BY THE COMMISSION:

On December 7, 2011, we issued Order No. PSC-11-0553-FOF-EI, approving projected expenditures and true up amounts for environmental cost recovery factors. The Order contained two scrivener's errors that need to be corrected. On page 3, Order No. PSC-11-0553-FOF-EI is amended to replace "January 2012 through December 20121" with "January 2012 through December 2012." On page 5, subsection G, Order No. PSC-11-0553-FOF-EI is amended to replace "January 2011 through December 2011" with "January 2012 through December 2012."

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Order No. PSC-11-0553-FOF-EI is hereby amended to reflect the corrections identified above. It is further

ORDERED that Order No. PSC-11-0553-FOF-EI is reaffirmed in all other respects.

By ORDER of the Florida Public Service Commission this 13th day of December, 2011.

ANN COLE
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

MCB

DOCUMENT NUMBER-DATE
08915 DEC 13 =
FPSC-COMMISSION CLERK

EXHIBIT NO. 52

DOCKET NO: 20180007

WITNESS: Sole

PARTY: FPL

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT

TPCCMP Project O&M Expenses and Capital Costs

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 52
PARTY: SACE
DESCRIPTION: TPCCMP Project O&M Expenses and Capital Costs

TPCCMP Projected O&M Costs

Description of Expenditures	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	Requirement
Recovery Well System	$ 6,953,997	$ 1,553,999	$ 81,500	$ 581,500	$ 81,500	$ 81,500	$ 81,500	$ 81,500	$ 81,500	$ 581,500	$ 10,159,996	Miami - Dade County Consent Agreement
Groundwater Monitoring Clusters to Model Conditions in Model Lands Basin	$ 1,854,558	$ -	$ -	$ -	$ -	$	$ -	$ -	$ -	$ -	$ 1,854,558	Miami - Dade County Consent Agreement Addendum
Recovery Well System - UIC Deep Injection Wells Testing & Monitoring	$ 912,599	$ 961,942	$ 961,942	$ 961,943	$ 961,943	$ 961,943	$ 961,943	$ 961,943	$ 961,943	$ 961,943	$ 9,570,084	Miami Dade County Consent Agreement
Sediment Removal	$ 10,513,814	$ 5,250,000	$ 5,250,000	$ 5,250,000	$ 250,000	$ 250,000	$ 250,000	$ 250,000	$ 250,000	$ -	$ 27,513,814	State of Florida Consent Order
Additional Monitoring Cluster Wells	$ 1,837,072	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,837,072	State of Florida Consent Order
Nutrient Management Plan / Algae Control & Remediation	$ 2,333,497	$ 3,000,000	$ 1,000,000	$ 1,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,333,497	State of Florida Consent Order
Monitoring / Mitigation /Reporting/CSEM & Project Support	$ 8,672,795	$ 2,833,882	$ 2,463,933	$ 2,495,787	$ 1,342,052	$ 1,342,052	$ 1,342,052	$ 1,342,052	$ 1,342,052	$ 1,342,052	$ 24,518,709	State of Florida Consent Order
Monitoring and Reporting - Monthly and Quarterly Reports	$ 4,571,594	$ 5,205,096	$ 4,721,097	$ 4,738,060	$ 4,756,039	$ 4,756,039	$ 4,756,039	$ 4,756,039	$ 4,756,039	$ 4,352,071	$ 47,368,113	State of Florida Consent Order
Total ECRC O&M	**$ 37,649,926**	**$ 18,804,919**	**$ 14,478,472**	**$ 15,027,290**	**$ 7,391,534**	**$ 7,391,534**	**$ 7,391,534**	**$ 7,391,534**	**$ 7,391,534**	**$ 7,237,566**	**$ 130,155,843**	

TPCCMP Projected Capital Costs

Description of Expenditures	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	Requirement
Barge Canal Turning Basin Back Fill	$ 13,128,375	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,128,375	State of Florida Consent Order
Turtle Point Back Fill	$ 5,630,071	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,630,071	State of Florida Consent Order
Recovery Well System	$ 20,364,279	$ 4,331,557	$ 118,400	$ 118,400	$ 118,400	$ 118,400	$ 118,400	$ 118,400	$ 118,400	$ 118,400	$ 25,643,036	Miami - Dade County Consent Agreement
Floridan Aquifer System Wells		$ 1,831,909	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,831,909	
Total ECRC Capital	**$ 39,122,725**	**$ 6,163,466**	**$ 118,400**	**$ 118,400**	**$ 118,400**	**$ 118,400**	**$ 118,400**	**$ 118,400**	**$ 118,400**	**$ 118,400**	**$ 46,233,391**	

$ 176,389,234 Total Project 2017-2026

$ 176.4

Florida Power & Light Company
Docket No. 20170007-EI
TPCCMP Project O&M Expenses and Capital Costs
Exhibit MWS-14, Page 1 of 1

EXHIBIT NO. 53

DOCKET NO: 20180007

WITNESS: Sole

PARTY: FPL

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT

DERM Consent Agreement Addendum

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 53
PARTY: SACE
DESCRIPTION: DERM 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 execut on 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 05/16/2020

Before me, the undersigned authority, personally appeared Randy P. LaBauve who after being duly sworn, deposes and says that he has read the foregoing.

Subscribed and sworn to before me this 12th day of August, 20 16 by Randy R LaBauve.
(Name of affiant)

Personally Known ✓ or Produced Identification ____.
(Check One)

Type of Identification Produced: _____

Notary Public

DO NOT WRITE BELOW THIS LINE OFFICE USE ONLY

Date

Lee N. Hefty, Director
Environmental Resources Management

Witness

Witness

EXHIBIT NO. 54

DOCKET NO: 20180007

WITNESS: Sole

PARTY: FPL

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT

DERM Letter July 7, 2017

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 54
PARTY: SACE
DESCRIPTION: DERM 7.7.2017 letter

MIAMI-DADE COUNTY
Carlos A. Gimenez, Mayor

Department of Regulatory and Economic Resources
Environmental Resources Management
701 NW 1st Court, 4th Floor
Miami, Florida 33136-3912
T 305 372-6754 F 305-372 6759
miamidade.gov

July 7, 2017

Mr. Matthew Raffenberg, Director
Environmental Licensing and Permitting
Environmental Services Department
Florida Power & Light Company
700 Universe Boulevard (JES/JB)
Juno Beach, FL 33408

CERTIFIED MAIL NO.: 7001 2510 0001 1765 4244
RETURN RECEIPT REQUESTED

Re: Site Assessment Report (SAR) dated March 17, 2017 and submitted pursuant to Paragraph 34.b. of Addendum 1 to the October 7, 2015 Consent Agreement for FPL's Turkey Point facility 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, CLI-2016-0303, HWR-851)

Dear Mr. Raffenberg:

The Department of Regulatory and Economic Resources-Division of Environmental Resources Management (DERM) has reviewed the referenced submittal received on March 17, 2017. Based on the data and information provided, DERM does not concur at this time with the conclusions and recommendations presented in the report. The following is required to allow for further evaluation of the SAR conclusions and recommendations:

1. The sediment data referenced in DERM's Site Assessment Plan (SAP) approval letter dated December 21, 2016 shall be provided.

2. The results of the tritium analysis per DERM's April 20, 2017 request shall be provided.

3. Maps scaled for E-sized sheets showing groundwater elevation contours shall be provided.

4. Maps scaled for E-sized sheets showing ammonia concentration contours for shallow wells (less than 16 ft.) and separately for intermediate depth wells (20 to 30 ft.) sampled shall be provided.

5. A single map scaled for E-sized sheet showing the concentrations of all the nitrogen species evaluated (measured and calculated) in groundwater as well as surface water shall be provided.

6. Please provide specific data and information used to support the following two statements in paragraph 3 of page ES-1: *"... The areas studied at Turkey Point which possess these attributes and elevated ammonia are similar to many locations in Coastal Southeast Florida. Regional studies of background surface water quality data for Biscayne Bay indicate that ammonia can be detected at many locations greater than 0.5 mg/L and that the concentrations can vary both temporally and spatially."*

7. Please provide data and information from the Site Conceptual Model referenced in paragraph 2 of page 13 that supports the following statement: "... *Groundwater gradient data presented in the Site Conceptual Model for PTN (CRA, 2009) indicates that groundwater flows for shallow wells are from the Plant Complex towards the Turning Basin or Intake Canal so the wells do not appear to be influenced by quality in the Turning Basin...*" Also please clarify the last part of the statement regarding the wells not being influenced by quality in the Turning Basin.

8. Please provide the correlation of Turkey Point data to regional background data referenced in the 4th bullet of paragraph 1 of page 19. The submittal shall include all supporting data and information used for the correlation.

9. Please provide data and information to support the statement on page 22 of the SAR "that the ammonia appears to be limited in extent". Is this statement limited to the ammonia that has been detected in surface waters under the Site Assessment Plan?

10. Please provide the specific data from the studies referenced in the second paragraph of page 22 that support the conclusion that the SAR results, including where the high ammonia concentrations have been detected, are consistent with background data for Biscayne Bay. In addition, copies of all other reports cited in the SAR and listed in Attachment B shall be provided in hardcopy or by electronic means.

11. All information required pursuant to the December 21, 2016 Site Assessment Plan approval shall be provided. Clarification is also required for the conclusion regarding the ammonia source FPL attributes to "the decomposition of wetland and aquatic plant material". During the May 10, 2017 meeting in the DERM offices, FPL explained that this conclusion refers to wetland vegetation "outside" the cooling canal system (CCS) and not the seagrass or mangrove vegetation that has died within the CCS. Therefore FPL shall clarify what it has concluded concerning the wetland and aquatic plant material that has decomposed within the CCS. FPL shall explain the degree to which it considers the wetland and aquatic plant material that has decomposed within the CCS to be a source of ammonia in the ground water or surface water at and adjacent to the FPL facility. In addition, FPL shall describe the fate of the organic nitrogen in the surface water as that water leaves the CCS and provide all data and information to support the conclusion. FPL shall provide all available information in support of any conclusion that the CCS is not an ammonia source pursuant to the requirements of the consent agreement and the approved Site Assessment Plan. This information shall include an evaluation of available tritium data including data required pursuant to item 2 above in support of SAR conclusions regarding ammonia sources.

Additionally, based on the groundwater characteristics documented in the area of the wastewater treatment plant and the fuel tank farm (MW South, MW North, FTF-SW, FTF-NW) DERM requires resampling of these wells for the parameters listed on Attachment A. FPL shall provide a minimum of fifteen (15) working days written notice to allow DERM the option to split samples. If resampling confirms the data previously submitted, further evaluation of the ammonia source(s) may be required for this area.

Be advised that DERM has the option to split any samples deemed necessary with the consultant or laboratory at the subject site. The consultant collecting the samples shall perform field sampling work in accordance with the Standard Operating Procedures provided in Chapter 62-160, Florida Administrative Code (FAC), as amended. The laboratory analyzing the samples shall perform laboratory analyses pursuant to the National Environmental Laboratory Accreditation Program (NELAP) certification requirements. If the data

submitted exhibits a substantial variance from DERM split sample analysis, a complete resampling using two independent certified laboratories will be required.

DERM shall be notified in writing a minimum of 15 working days prior to the implementation of any additional sampling or field activities. Email notifications shall be directed to DERMPCD@miamidade.gov as well as Barbara.brown@miamidade.gov . Please include the DERM file number on all correspondence.

Therefore, within ninety (90) days of receipt of this letter, FPL is hereby required to submit to DERM for review the additional data and information requested above in paper as well as electronic format (except for the requested reports in Appendix B, which may be provided solely in electronic format). Please provide all numerical data (laboratory analysis results, physical water quality, etc.) in Excel® format. Failure to adhere to the items and timeframes stipulated above may result in further enforcement action for this site.

Any person aggrieved by any action or decision of the DERM Director may appeal said action or decision to the Environmental Quality Control Board (EQCB) by filing a written notice of appeal along with submittal of the applicable fee, to the Code Coordination and Public Hearings Section of DERM within fifteen (15) days of the date of the action or decision by DERM.

Please contact me at (305) 372-6522 if you have any questions regarding this matter.

Sincerely,

Craig K. Grossenbacher, Chief
Water Resources Coordination Division

Attachment A: sampling parameters
Attachment B: list of reports and publications

c: Scott Burns, FPL
Alan Katz, FPL
Lee Hefty, DERM Director
Lisa Spadafina, DERM
Barbara Brown, DERM
Wilbur Mayorga, DERM
Virginia Walsh, WASD

EXHIBIT NO. 55

DOCKET NO: 20180007

WITNESS: Sole

PARTY: FPL

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT

DERM Letter July 10, 2018

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 55
PARTY: SACE
DESCRIPTION: DERM 7.10.18 letter

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

July 10, 2018

Certified Mail No. 70172400000078352802
Return Receipt Requested

Matthew J. Raffenberg, Sr. Director
Environmental Licensing and Permitting
Florida Power & Light Company
700 Universe Blvd.
Juno Beach, Florida 33408

RE: Site Assessment Report (SAR) dated March 17, 2017 and the SAR Supplemental Information dated November 11, 2017, submitted pursuant to Addendum 1 dated August 15, 2016 of the Consent Agreement between Florida Power & Light (FPL) and Miami-Dade County, Division of Environmental Resources Management for FPL's Turkey Point facility 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, CLI-2016-0303, HWR-851)

Dear Mr. Raffenberg:

The Department of Regulatory and Economic Resources-Division of Environmental Resources Management (DERM) has reviewed the documents referenced above along with applicable historical DERM records for the site. DERM's evaluation of the report as discussed at our January 10, 2018, meeting identified the following:

1. An evaluation of the total ammonia (ammonia) groundwater data provided in the referenced report along with historical data (since 2010) from groundwater monitoring wells within (TP-GW13 series) and immediately adjacent, to the Cooling Canal System (CCS) (TPGW-1, TPGW-2, TPGW-10, and TPGW-14 series) indicates a statistically significant increasing trend (Mann Kendall Trend Analysis; 0.05 significance level, 0.95 confidence level) and a concentration gradient emanating from the CCS at the deep and intermediate intervals.

2. DERM finds that the total ammonia concentrations documented in several sampling locations at the Barge basin, Turtle Point Canal, Card Sound Canal, S-20 Get Away Canal, and the Sea-Dade Canal exceeded the applicable Miami-Dade County surface water standard. DERM acknowledges that the documented elevated surface water ammonia concentrations may be attributable to several contributing sources, including factors not directly related to the operation of the CCS. However, based on an evaluation of other associated water quality data, such as tritium concentrations and

temperature, DERM finds that the data supports that the CCS is a contributing source to the ammonia concentrations observed in areas which exceed the applicable standard.

Based on the above and to address the CCS's contribution to the surface water ammonia exceedances and to monitor any potential migration of the groundwater ammonia plume, DERM requires the following:

1. Submittal of a plan that identifies strategies or actions FPL shall implement to address CCS nutrient impacts to groundwater and surface water resources beyond the boundaries of the CCS. Due to documented movement of CCS water through the groundwater pathway, it is acknowledged that management of water quality within the CCS may be effective in reducing water quality impacts observed beyond the CCS facility boundaries. Therefore, the plan may include an evaluation of nutrient sources within the CCS and may include proposed operational, process, or engineering modifications to reduce the level of nutrients within the CCS, and improve the general ecological health of the CCS, in order to eliminate CCS discharges to surrounding groundwater and surface waters that result in exceedances of state water quality criteria and Miami-Dade County water quality standards.

2. Implementation of the FPL proposed plan to fill the barge basin and Turtle Point canal, as well as submittal of plans to fill or otherwise address water quality impacts in the additional areas as referenced above.

3. Resampling of surface water sampling point SDS-SWCCS (March 17, 2017 SAR, Figure 6) at all depths to confirm the concentrations of total ammonia (31 mg/l) documented.

4. Submittal of a proposal, including but not limited to groundwater and surface water monitoring, to evaluate the effectiveness of the measures implemented pursuant to requirements 1 and 2 above. The plan shall include, without limitation:

    a. Sampling and analysis of groundwater from monitoring wells TPGW-17, TPGW-18, TPGW-19, TPGW-1, TPGW-2, TPGW-13, TPGW-12, TPGW-15, L-3, L-5, G-21, and G-28 and the groundwater recovery wells. Groundwater shall be analyzed for nutrients, including but not limited to the species of nitrogen (ammonium ion, total ammonia, nitrate nitrite as N, etc.,) total phosphorus, etc.

    b. A representative number of groundwater and surface water monitoring locations to the east and south of the CCS to be sampled and analyses as indicated in Item 4a above. Note that this may include utilization of existing monitoring stations where appropriate.

July 10, 2018

5. The evaluation of the performance of the DERM approved groundwater recovery well system, shall include an evaluation of the spatial and temporal trends for groundwater ammonia, an evaluation and quantification of ammonia mass removal.

Therefore, within ninety (90) days of receipt of this correspondence a report (s) that addresses the above requirements. Be advised that the groundwater/surface water nutrient monitoring proposal may propose a sampling and reporting frequency consistent with preexisting sampling programs as applicable (e.g., uprate monitoring, DERM Class I permit (CA) monitoring, etc.,).

Be advised that failure to comply with the above may result, at a minimum, in the assessment of penalties as outlined in the subject Consent Agreement.

If you have any questions concerning the above matters please contact me at wilbur.mayorga@miamidade.gov or via telephone at (305) 372-6700

Sincerely,

Wilbur Mayorga, P.E., Chief
Environmental Monitoring and Restoration Division
DERM

ec: Scott Burns, FPL – Scott.Burns@fpl.com
John Truitt, FDEP - John.Truitt@dep.state.fl.us
Lee Hefty, DERM
Lisa Spadafina, DERM
Craig Grossenbacher, DERM
Pamela Sweeney, DERM
Barbara Brown, DERM
Lorna Bucknor, DERM
Virginia Walsh, WASD

EXHIBIT NO. 54

DOCKET NO: 20180007

WITNESS: Sole

PARTY: FPL

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT

DERM Consent Agreement - Excerpt

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 56
PARTY: SACE
DESCRIPTION: DERM Consent Agreement Excerpt

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").

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

EXHIBIT NO. 57.

DOCKET NO: 20180007-EI

WITNESS: Michael W. Sole

PARTY: FPL

DESCRIPTION: FPL's October 8, 2018 response to DERM's July 10, 2018 letter

PROFFERED BY:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20180007-EI EXHIBIT: 57
PARTY: FPL
DESCRIPTION: FPL 10.8.18 letter response to DERM 1.10.18 letter

October 8, 2018

Wilbur Mayorga, P.E.
Chief, Environmental Monitoring and Restoration Division
Division of Environmental Resources Management
701 N.W. 1st Court 6th Floor
Miami, FL 33136-3912

RE: Miami Dade County July 10, 2018 Letter regarding the FPL Site Assessment Report (SAR) dated March 17, 2017 and the SAR Supplemental Information Submittal dated November 11, 2017

Dear Mr. Mayorga:

This correspondence is in response to your July 10, 2018 letter regarding the Florida Power & Light (FPL) Site Assessment Report (SAR) dated March 17, 2017 and the SAR Supplemental Information dated November 11, 2017, submitted pursuant to Addendum 1 dated August 15, 2016 of the Consent Agreement between FPL and Miami- Dade County. FPL appreciates your review and approval of the SAR activities and direction related to ammonia concentrations adjacent to the Turkey Point facility. In complying with the July 10th DERM letter, FPL understands that the requirements and obligations of Paragraph 34.c. and d. of the August 15, 2016 Consent Agreement Addendum are met.

In the July 10th letter, DERM states that based on their evaluations:

1) Historical data collected since 2010 from groundwater monitoring wells within (TPGW-13) and immediately adjacent to the Cooling Canal System (CCS) (TPGW-1, TPGW-2, TPGW-10, and TPGW-14) indicate a statistically significant increasing trend and a concentration gradient emanating from the CCS at the deep and intermediate intervals.

   FPL Response: As noted in the SAR, groundwater ammonia concentrations surrounding the CCS are consistently below Chapter 24-44 Clean-up Target Levels (CTLs) for ammonia in groundwater (Section 24-44.(2)(f)(v) of the Code of Miami-Dade County) and as such, provide an acceptable level of protection for human health, public safety and environmental resources and are below the point at which a site rehabilitation action is determined to be accomplished (Section 24-44.(2)(a) of the Code of Miami-Dade County).

2) The total ammonia concentrations documented in several sampling locations at the Barge Basin, Turtle Point Canal, Card Sound Canal, S-20 Get Away Canal, and the Sea-Dade Canal exceeded the applicable Miami-Dade County surface water standard. DERM acknowledges that the documented elevated surface water ammonia concentrations may be attributable to several contributing sources, including factors not directly related to the operation of the CCS. However, based on an evaluation of other associated water quality data, such as tritium concentrations and temperature, DERM finds that the data supports that the CCS is a

contributing source to the ammonia concentrations observed in areas which exceed the applicable standard.

FPL Response: The FPL Site Assessment Report identified ammonia concentrations that exceeded applicable MDC surface water standards in five deep man made drainage canals adjacent to the CCS. The elevated ammonia values were located in bottom samples where dissolved oxygen levels were less than 1.0 mg/L. Ammonia levels in the middle and upper portions of the water column were compliant with county ammonia standards with the exception of middle samples in the Turtle Point Canal where the dissolved oxygen levels were also less than 1.0 mg/L. There are no state numeric ammonia standards for marine waters.

Average ammonia levels within the CCS canals are well below Chapter 24-42(4) surface water standards of 0.5 ppm (Source: EPU semi-annual data from 6/2010 through 3/2018: 0.33 mg/L and L-31E weekly data from 5/31/2015 through 8/6/2018: 0.26 mg/L). Measured ammonia concentrations in several of the deep samples (TPSWC-7D, TPSWC-8D, S20Get-CCS-B, SDC-SWCCS-B, and TPBBSW-8B) greatly exceeded the total nitrogen concentrations in the CCS and in groundwater beneath the CCS demonstrating that there are sources of nitrogen other than the CCS causing exceedances of county ammonia standards in the bottom of the deep canals.

As identified in the SAR, while the data cannot delineate contribution levels of groundwater underlying the CCS to the ammonia levels in surrounding waters, the SAR analysis demonstrated that for those adjacent surface water areas that exceeded the Miami-Dade limit for ammonia, the maximum contribution was 2 percent or less. The SAR also established that the range of contribution (including Surface Waters that met the 0.5 mg/l standard) ranged from 0.4 to 16 percent. Thus, if there is any contribution to ammonia concentrations in adjacent surface water from groundwater beneath the CCS, it is de minimis.

While offsite groundwater concentrations of ammonia are below action levels established in Chapter 24 of the Code of Miami-Dade County and groundwater concentrations of ammonia provide a de minimis contribution to the stratified elevated ammonia found in the stagnant manmade deep canals cut into the Biscayne aquifer, FPL has already taken numerous successful steps and is pursuing additional actions that address nutrient contributions from the Turkey Point facility as outlined below. FPL will continue to work with DERM to assess responses resulting from FPL's implementation of the following actions in good faith that these actions are reasonable, responsive and compliant with the CA, as amended, and with the understanding that elevated surface water ammonia concentrations are attributable to several contributing sources, including factors not directly related to the operation of the CCS.

The FPL strategy to address CCS nutrients consists of three elements: 1) continued implementation of CCS canal practices, 2) external canal practices, and 3) monitoring and reporting. This approach is consistent with FPL 2016 Nutrient Management Plan as required and approved by the Florida Department of Environmental Protection (FDEP) pursuant to Paragraph 21.b of the FDEP 2016 Consent Order.

A summary of DERM's requirements as stated in the July 10, 2018 letter and where they are addressed in this response is provided below:

1) Submit a plan that identifies strategies or actions FPL shall implement to address CCS nutrient impacts to groundwater and surface water resources beyond the boundaries of the CCS;

   FPL Response: See Sections 1 and 2

2) Implement the FPL permitted plan to partially fill the Barge Basin and Turtle Point Canal, as well as submittal of plans to fill or otherwise address water quality impacts in the Card Sound; Canal, S-20 Get Away Canal, and the Sea-Dade Canal;

   FPL Response: See Section 2

3) Resample surface water sampling point SDS-SWCCS;

   FPL Response: See Section 3

4) Submit a groundwater and surface water monitoring plan to evaluate the effectiveness of the measures implemented pursuant to requirements 1 and 2 above; and

   FPL Response: See Section 3

5) Expansion of the evaluation of the performance of the DERM approved hypersaline groundwater recovery well system to include an evaluation of the spatial and temporal trends for groundwater ammonia, and a quantification of ammonia mass removal.

   FPL Response: See Section 3

1. CCS Canal Practices

In September 2016, FPL developed the Nutrient Management Plan for the CCS in compliance with Paragraph 21.b of the FDEP Consent Order that outlined the potential sources of nutrients found in the CCS, including chemical products used for plant operations and included a plan for reducing nutrient levels in the CCS (FPL, 2016). FPL has shared a copy of this report with DERM. The report found:

- The major source of nutrients in the CCS water column came from the die-off and decomposition of sea grasses between 2010 and 2013, caused by elevated CCS average salinities above 55 psu
- Additional sources of nutrients are primarily environmental in nature (algae, groundwater seepage, berm erosion and plant biomass, atmospheric deposition, and canal sediment storage)
- To a lesser degree, controlled water sources contributed to nutrient concentrations (water added from the L-31E canal, marine wells, interceptor ditch pumpage and Floridan freshening) while industrial sources related to plant operations were a minor contributor to total loading

Under the current algae dominated nutrient based canal system, nutrients within the halotolerant cyanobacteria are reintroduced to the water column when algae cells die and release nutrients that support the growth of new algae cells thereby recycle the nutrients in the water column. In order to break this cycle, the CCS canal nutrients need to be reduced to levels which will not sustain the persistent algae dominance and facilitate the re-establishment of seagrasses which for decades had successfully moderated nutrients in the

CCS. The 2016 plan identified target nutrient levels for the CCS at 2.5 mg/L for total nitrogen and 0.02 mg/L for total phosphorous. Target levels are a management guide, subject to variability based on seasonal and environmental factors and should be reviewed on an appropriate averaging interval.

Canal management actions implemented by FPL to date (canal sediment removal, canal berm management, vegetation management, canal freshening with low nutrient Floridan aquifer, and groundwater extraction) have been effective in reducing nutrient concentrations in the cooling canals and in shallow groundwater near the canals. Since reaching its peak in September 2013, semi-annual total nitrogen concentrations in the CCS canals have dropped from 15.2 mg/L to 3.5 mg/L in September 2018 with the March and September 2018 levels being the lowest measured since 2011 (Figure 1). Phosphorous concentrations peaked at 0.087 mg/L in September 2014 and have declined to 0.026 mg/L by September 2018 (Figure 2).

Over the past several years, FPL has been evaluating and pilot testing mechanical and biologic means of removing/sequestering nutrients in the CCS. This plan builds on the information gained in implementing the 2016 nutrient management plan and considers chemical, mechanical and biologic based actions to further reduce CCS nutrients going forward as described below.

Figure 1: Semi-Annual average CCS total nitrogen concentrations: 6/2010 through 9/2018

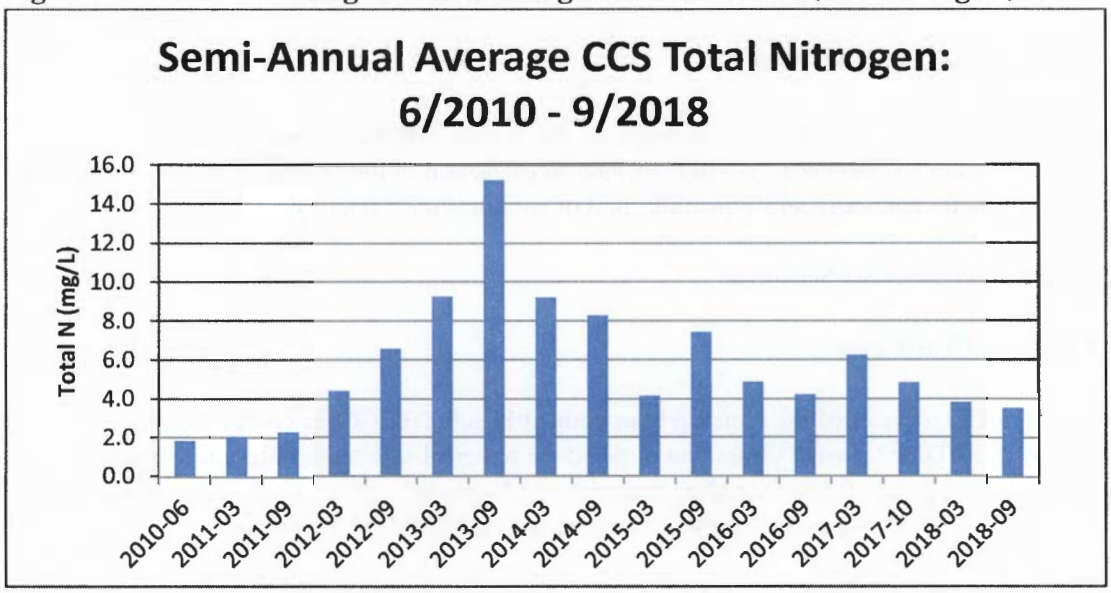
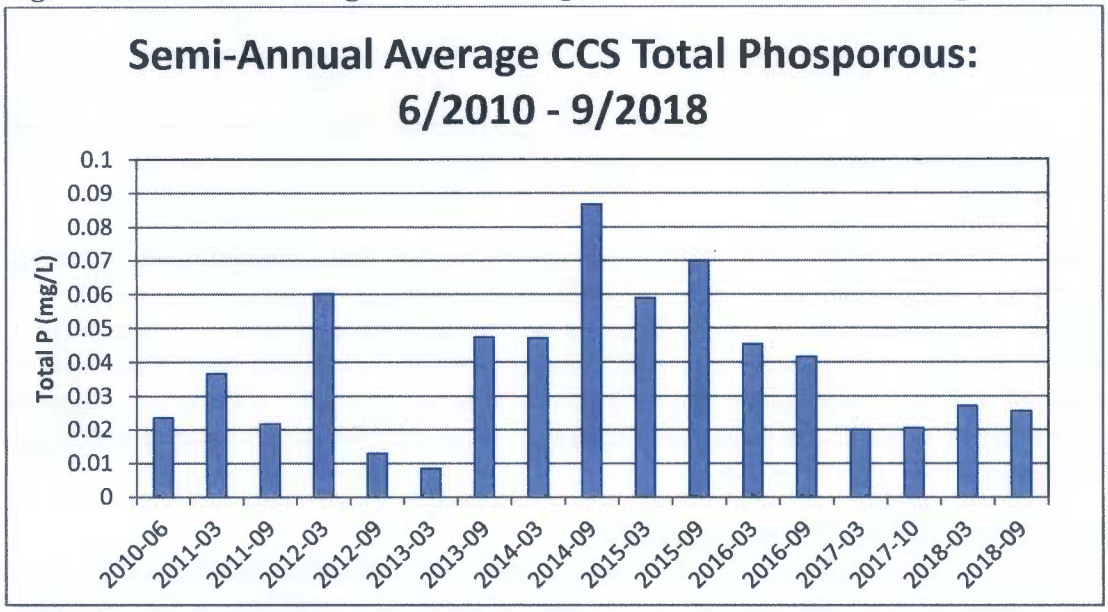


Figure 2: Semi-Annual average CCS total nitrogen concentrations: 6/2010 through 9/2018



CCS Canal Practices; Chemical/Mechanical Treatment Options:

Nutrient and Algae Removal: Actions to remove nutrients in the cooling canal water column and/or the removal of algal biomass consider both chemical and mechanical means. For the removal of nutrients in the cooling canals, several coagulants and flocculants have been evaluated for in situ applications (where chemical nutrient sequestering occurs within the canal system) and on a treatment plant scale (treatment external to the canals). Trials have included bench testing and pilot scale tests. For removal of algae biomass, FPL has evaluated chemical methods (algaecides) and mechanical treatments (ultrasonic breakdown, filtration, and protein skimming methods using dissolved air flotation).

Challenges identified with chemical and mechanical treatment options included impacts of salinity on performance of flocculants and air flotation methods, cost feasibility of large scale treatment systems, persistence of chemicals introduced to the system, and potential for impacts to fish and wildlife that utilize the CCS. At this time, evaluation of technically, environmentally and economically feasible chemical and/or mechanical treatment methods suitable for the CCS are ongoing. The following are nutrient reduction actions that have been implemented or are being implemented within the CCS

Foam Removal/Harvesting: Cooling water circulation pumps agitates and aerates CCS water containing organic compounds and nutrients. The organic compounds and nutrients increase surface tension of water causing air bubbles to form and stick together into foam. Chemical analyses of the CCS foam indicated the water forming the bubbles is high in nitrogen and phosphorous compared to CCS canal water (10 to 20 times higher per unit volume than canal water). FPL is evaluating the potential for developing a foam collection and condenser system by which foam can be collected, rendered to liquid and disposed of along with hypersaline groundwater from the RWS down the DIW. Pilot testing of foam collection and disposal system has been encouraging (Figure 3). Evaluation of the feasibility of a large scale collection-condensation and disposal system linked to the DIW for disposal is underway.

Salinity Reduction: As a result of temperature, thermal loading via power generation and periods of low rainfall, the CCS experiences periods when evaporation exceeds freshwater recharge and salts, including

nutrients, become more concentrated in the CCS. FPL is using fresh water from the upper Floridan aquifer to replace freshwater lost to evaporation to reduce the concentration of salts/nutrients in the CCS. Reductions of salinity are a necessary component for the re-establishment of seagrass beds within the CCS which remains a proven biologically based nutrient sequestering system in the CCS. Since UFA freshening began in November 28, 2016, the average annual CCS salinities have been dropping despite several significant dry spells. FPL is encouraged by the progress in reducing CCS salinity and is continuing to evaluate additional freshwater sources.

Sediment Maintenance: CCS canal sedimentation impacts thermal efficiency and thereby, the salinity of the CCS. Removal of sediment from the water column and consolidating on berm tops reduces the bioavailability of nutrients within the sediment. Phase I of canal maintenance dredging was completed in 2015 resulting in significant improvements in thermal efficiency. Concurrent reductions in CCS salinities, total phosphorous and total nitrogen concentrations have been observed although it is not clear the degree to which these changes are attributable to maintenance dredging. At this time there are no immediate plans for additional dredging.

CCS Canal Practices; Biologic Treatment Options:

CCS Berm Maintenance Practices: CCS berms are a source of nutrients that reach the cooling canals as runoff over non-stabilized soil, and transport of plant material. Recent FPL evaluation of Australian pine (*Casuarina equisetifolia*) in and surrounding the CCS indicates significant amounts of nitrogen and phosphorous are added to the CCS in the form of vegetative litter and decay. Runoff of oxidized soils from non-vegetative berms adds nutrients and associated sediment reduces hydraulic connection of the cooling canals to groundwater. To address this, FPL is implementing a vegetative berm management program including removal of Australian pine and other exotics and restoring native grasses to stabilize berm soils (Figure 4). Management of berm vegetation uses periodic control burns instead of chemical treatments. Side slope erosion associated with Hurricane Irma is being evaluated to determine whether restoration work is needed.

CCS Seagrass Re-establishment: A healthy sea grass population expected help balance the nutrients in the CCS and sequester nutrients in biomass. A healthy sea grass system will also provide fish and invertebrates protected habitat to grow and reproduce. In September 2018, FPL implemented a field scale test planting of a total of 3 acres of *Ruppia maritima* at separate locations in the CCS to determine whether current conditions will support the repatriation of historic nutrient moderating seagrass meadows in the CCS. The test plants were pre-conditioned to withstand high salinity water prior to mechanical planting in the CCS (Figure 5). *Ruppia maritima* was selected as the initial seagrass species due to the higher salinity tolerances of the plant and was historically the dominant grass in the CCS. The test planting sites were selected based on screening criteria that considered substrate quality, water depth, light penetration, temperature, and salinity. Prior to this pilot, several small scale successful planting tests were conducted in the canal system and in test tanks. Based on the results of the pilot, additional test plantings will be considered. Challenges to the success of seagrass plantings are light penetration (limited by cyanobacteria based turbidity) and hypersalinity.

Figure 3: CCS Foam Collection Pilot



Figure 4: Seagrass Planting Pilot: *Ruppia* plug planting barge in operation



Figure 5: CCS berm vegetation management pilot site



2. External Canals Practices

Canal Restoration/Partial Filling: FPL is moving forward with the restoration of the Barge Canal Turning Basin and the Turtle Point Canal as prescribed in the FDEP CO and requirement 2 of DERM's July 10, 2018 letter. FPL has received all federal, state and county permits for the project (August 17, 2018), selected a contractor, issued a notice to proceed (September 26, 2018) with construction to commence by the end of October 2018. Completion of both of the restorations is targeted by August 17, 2020. The two restoration projects entail partially filling the Barge Canal Turning Basin from an average existing depth of -30 ft. NAVD to a depth of -15 ft. NAVD., and to fill and plant mangroves in the western third of the Turtle Point Canal while filling the remainder of the remnant canal to -7 ft. NAVD (Figures 6 and 7).

Figure 6: Cross section of the Turtle Point canal restoration

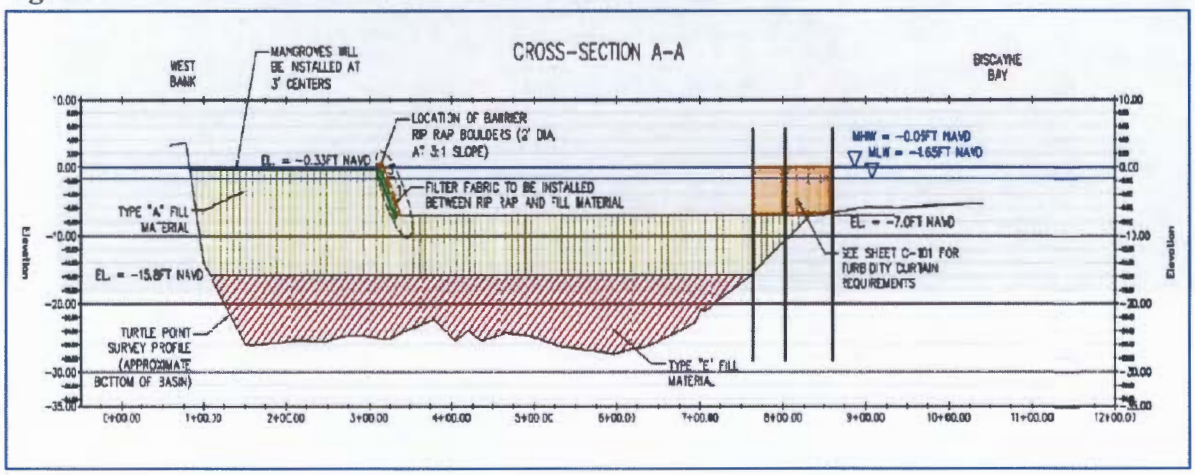
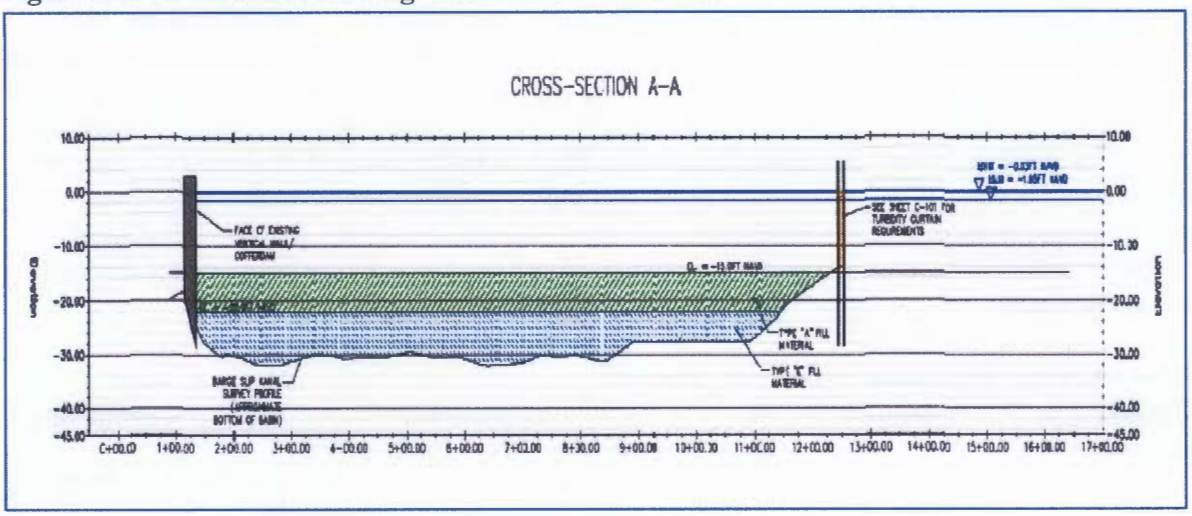


Figure 7: Cross section of the Barge Basin canal restoration



Groundwater Extraction: On May 15, 2018 FPL began operation of the approved Turkey Point Groundwater Recovery Well System (RWS). This system removes up to 15 mgd of hypersaline groundwater from the base of the Biscayne Aquifer via a series of ten extraction wells aligned along the western edge of the CCS and north to Palm Drive (FPL RWS Startup Report, 2018). Prior to the start of the RWS, FPL was permitted to conduct extended injection testing of the Turkey Point Class I Deep Injection Well (DIW) using 15 mgd of extracted hypersaline groundwater from beneath the CCS from the Biscayne Aquifer from September 29, 2016 to May 15, 2018. During this injection testing period and the first quarter of RWS operation, at total of 1.8 billion gallons of hypersaline groundwater from the base of the Biscayne aquifer has been removed and disposed of via permitted deep well injection. Based on ammonia data collected from the bottom of the Biscayne Aquifer in TPGW-1D, 2D, and 13D from September 2016 through March 2018 the estimated average ammonia concentration of groundwater extracted was 1.84 mg/L which indicates approximately 27,600 pounds of ammonia has been removed from groundwater beneath the CCS since September, 2016.

There are no other plans to fill or otherwise address unquantified water quality impacts for the Card Sound Canal, S-20 Get Away Canal, and the Sea-Dade Canal under development. FPL plans to continue implementation of the nutrient reduction actions within the CCS as outlined in this plan and execute the groundwater RWS which has already removed approximately 27,600 pounds of ammonia from groundwater beneath the CCS since September, 2016. To the extent, if any, CCS water has contributed to elevated levels of ammonia in these dead-end canals, the actions taken above are anticipated to minimize or eliminate such contribution.

3. Monitoring and Reporting

FPL and MDC DERM have jointly worked on identifying a monitoring program for the Consent Agreement and are finalizing the details at the time of this submittal. The monitoring network is summarized in Table 1. Quarterly sampling for nutrients collected by the RWS wells will be conducted at the DIW well. In addition, upon approval of this submittal, FPL shall collect grab samples from SDC-SWCCS from top, middle and bottom of the water column as requested in the DERM July 10th letter.

The results of the monitoring efforts will be posted on the FPL database. Groundwater monitoring data demonstrate groundwater ammonia levels are and have been below the County clean-up levels for years. Accordingly, the obligation to extract, evaluate the spatial and temporal trends for groundwater ammonia and quantify the ammonia mass removed below the clean-up target levels does not appear to be warranted. Nonetheless, FPL agrees to the continued collection of nutrients in groundwater under the CA monitoring plan and the resulting data will be provided to MDC. Collection and reporting of ammonia data along with other nutrient data should not be construed to mean or imply that FPL agrees to conduct monitoring or remedial actions at the direction of MDC that is not consistent with or expands upon County rules and authorities. FPL is committed to work with the County to find resolutions to any disagreements that may arise in this regard.

Table 1: Consent Agreement Monitoring Network

Sample Type	Station	Parameters	Frequency
Groundwater	TPGW-1, 2, 3, 4, 5, 6, 7, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19: L-3, L-5, G-21, and G-28	**Automated data:** Temperature, Specific Conductance, Salinity, Water elevation (Automated data not collected from L and G series wells)	Hourly
		Analytic data: Cl, Na, Ca, K, SO_4, Tritium, TAN, NH_4, NH_3, Nitrite plus Nitrate, TKN, TN, TP, and OP, Temperature, Specific Conductivity, Salinity, pH, Dissolved Oxygen, and Turbidity	Quarterly
Surface Water	TPSWC-1*, 2*, 3*, 4*, 5*, 7*[1], 8[2]: TPSWID-1*, 2*, 3*: TPBBSW-4, 6*, 7: TPSWCCS-1 & 6	**Automated data:** Temperature, Specific Conductance, Salinity, Water elevation	Hourly
		Analytic data: Cl, Na, Ca, K, SO_4, Tritium, TAN, NH_4, NH_3, Nitrite plus Nitrate, TKN, TN, TP, and OP, Temperature, Specific Conductivity, Salinity, pH, Dissolved Oxygen, and Turbidity	Monthly
Water from RWS	DIW	**Analytic data**: TAN, NH_4, NH_3, Nitrite plus Nitrate, TKN, TN, TP, and OP, Temperature, Specific Conductivity, Salinity, pH, Dissolved Oxygen, and Turbidity	Quarterly

*Surface water data collected at top and bottom of the water column

1. Replacement for TPBBSW-7B

2. Formerly TPSWTESTC-1

In summary, FPL will continue to work with the MDC DERM and FDEP to implement actions that address CCS ammonia contributions to groundwater and surface water outside of the FPL property consistent with our obligations under the MDC CA and FDEP CO. We are pleased to share with you the progress made by our efforts to date and look forward to continuing to work with you. As always, FPL is available to meet with you should you wish to discuss further.

Sincerely,

Matthew J. Raffenberg
Sr. Director of Environmental Licensing and Permitting

CC: Lee Hefty, DERM
John Truitt, FDEP
Scott Burns, FPL